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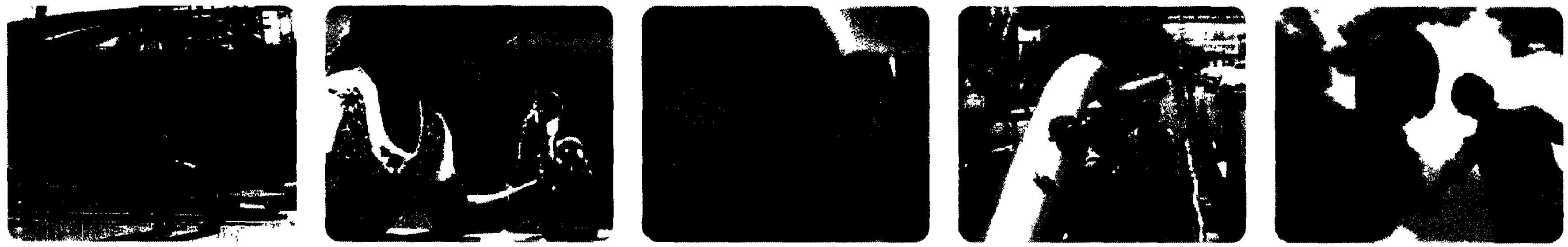

Intermountain Power Project (IPP) Greenhouse Gas (GHG) Reduction Feasibility Study

Presentation of Results

Las Vegas, NV

April 10, 2008

Background

The following presentation is based upon draft reports from Tasks 1 to 6. The information has not been finalized and is subject to modification.

Data has been developed at a pre-feasibility level, thus further analysis is required to substantiate conclusions.

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Introductions

Today's Presenters

- Bob Slettehaugh – Project Manager/CO_2 Capture
- Andy Byers – Regulatory Issues
- Matt Wood – Plant Improvements
- Matt Hunsaker – Renewable Energy

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Today's Agenda

Presentation Agenda

- General Overview of Black & Veatch (B&V)
- Key Take-aways
- Project Background
- GHG Emissions Trading Programs (Task 5)
- Efficiency Improvements (Task 1)
- Lunch Break
- Renewable Energy Resources (Tasks 2 & 6)
- Carbon Capture and Sequestration (Tasks 3 & 4)
- Economic Comparisons (Task 5)
- Recommendations and Conclusions

Please Ask Questions When You Have Them

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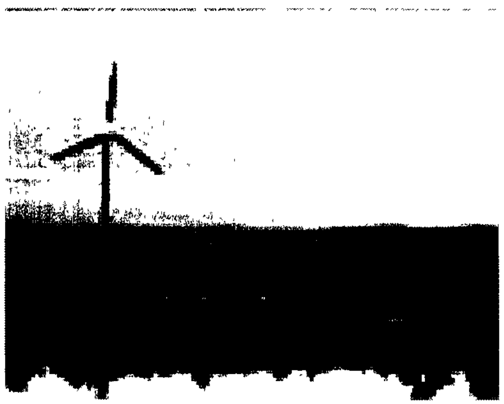
General Overview of Black & Veatch

Black & Veatch Corporation

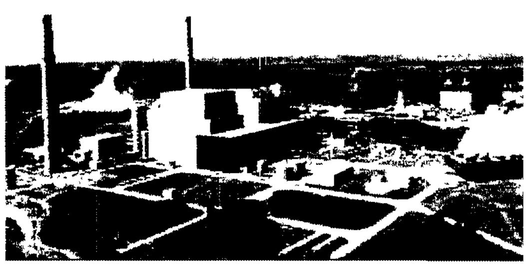
- Founded in 1915, headquarters in Kansas City
- A leading global engineering, consulting, and construction company
- Focus on infrastructure development in energy, water, information, and government markets
- Employee-owned company with more than 90 offices worldwide
- Over 9,000 Employees Worldwide
- Project Experience in Over 100 Countries on 6 Continents
- $3.2 Billion in Annual Revenues in 2007

B&V Energy offers a broad range of solutions for a global client base

Palmdale



Weston

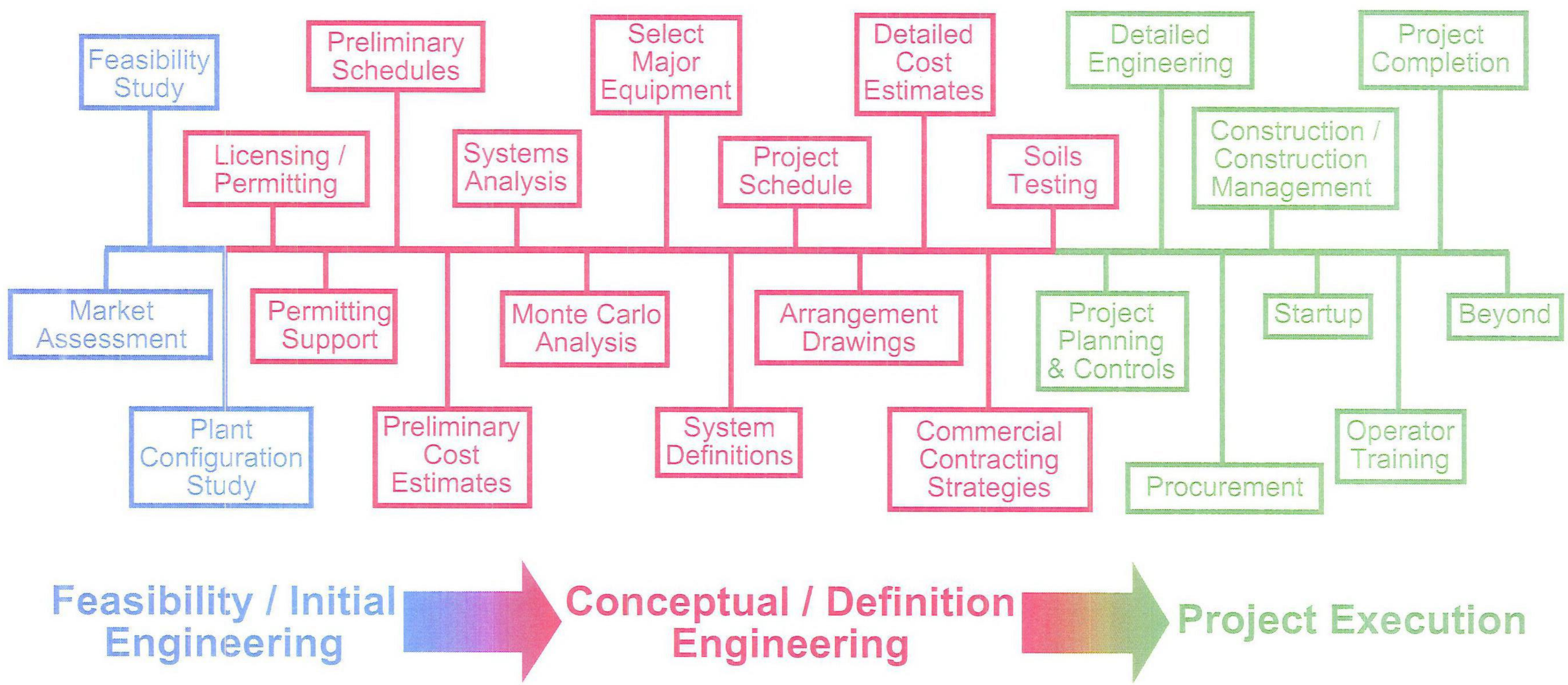


- Coal Plants
- Gas Turbines
- Combined Cycle
- Gasification / IGCC
- Nuclear
- Renewables
- AQCS
- Energy Services
- Power Delivery
- Substations
- Sulfur Recovery
- Natural Gas Processing
- LNG

Jefferson-Martin

Costa Azul

We Understand the Entire Life Cycle of an Energy Project



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Presentation Take-aways

Key Results and Conclusions

- IPP is a Best-in-Class Facility
- GHG Emissions Trading Scheme (ETS) Not Fully Defined
- Significant Reductions of CO_2 from IPP Require Carbon Capture and Sequestration (CCS)
  - Large Scale Capture Ready 2012-2015
  - Large Scale Sequestration Ready 2015-2020
- Viable Projects Available Today to Lower GHG Footprint

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Project Background

Project Scope

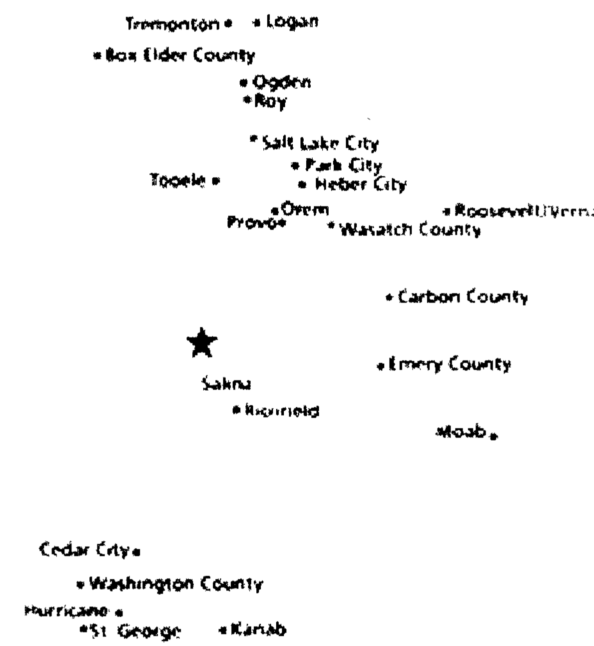
- Request from Intermountain Power Agency (IPA) and Southern California Public Power Authority (SCPPA)
- IPP GHG Reduction Feasibility Study
- Pre-Feasibility Level Study
- Work began in October 2007
- Final in April 2008

Purpose

Evaluate ways to reduce and/or capture CO_2 emissions from IPP coal fired Units 1 and 2. The ultimate goal, if achievable, is to reduce CO_2 emissions from Units 1 and 2 to meet California Energy Commission's (CEC) GHG Emission Performance Standard.

Intermountain Power Project

- Located near Delta, Utah
- Has two PC units with approximately 1,800 MW total capacity
- Engineered by Black & Veatch in the late 1980s
- Delivers power to 36 utilities in Utah and California
  - Most of the power is purchased by CA utilities



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Tasks as Defined in the Contract

- Task 1. Improve Efficiencies
- Task 2. Alternative Fuels
- Task 3. Developing Technologies
- Task 4. CO_2 Capture and Sequestration
- Task 5. Carbon Trading
- Task 6. Renewable Resources

General Approach to Study

- Maintain Existing Net Output from IPP
  - Efficiency Improvements Only
  - Renewable Resources Displace Coal
  - Purchase Power for CO_2 Capture/Compression
- Estimate Levelized Cost of CO_2
- Provide Screening Level Only

California GHG Reduction Policies

- **Executive Order S-3-05 signed June 1, 2005**
  - Sets statewide GHG reduction targets for 2010, 2020, and 2050
- **Global Warming Solutions Act of 2006 (AB 32)**
  - Enforceable limits beginning in 2012 to cap emissions at 1990 levels by 2020, compliance with market-based mechanisms
  - Must account for GHG emissions attributable to imported electricity consumed within the state
- **Senate Bill 1368 signed September 29, 2006**
  - CEC & California Public Utilities Commission (CPUC) establish 1,100 lbs/MWh GHG emission performance standard for new long-term power purchase agreements

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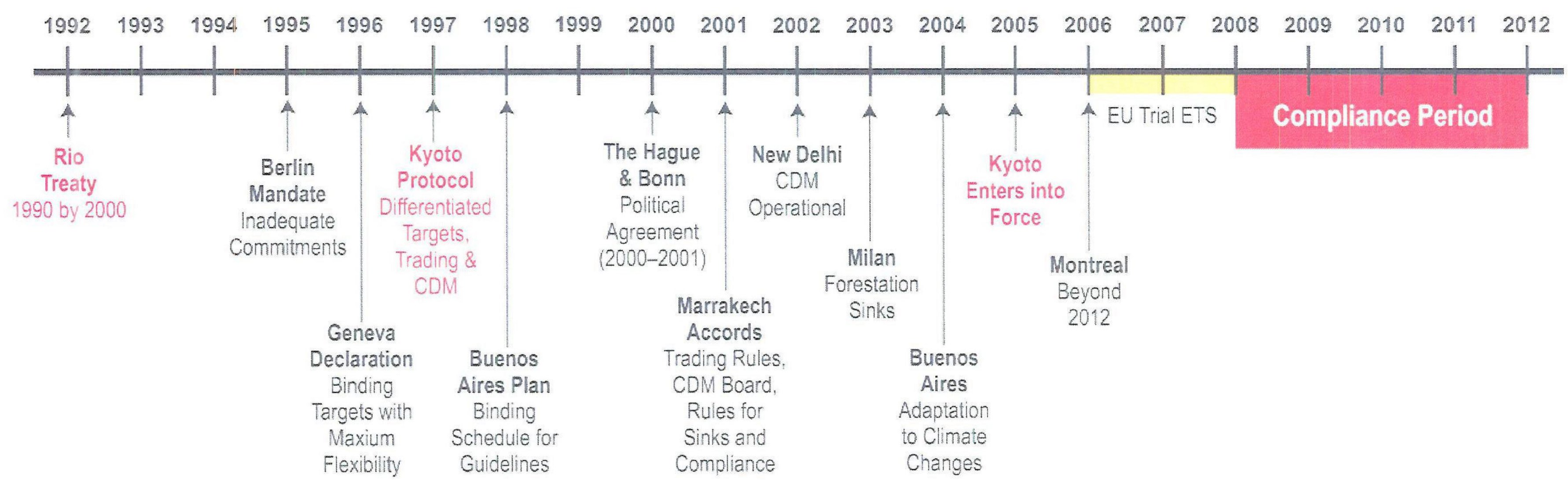
Task 5
GHG Emissions Trading Programs

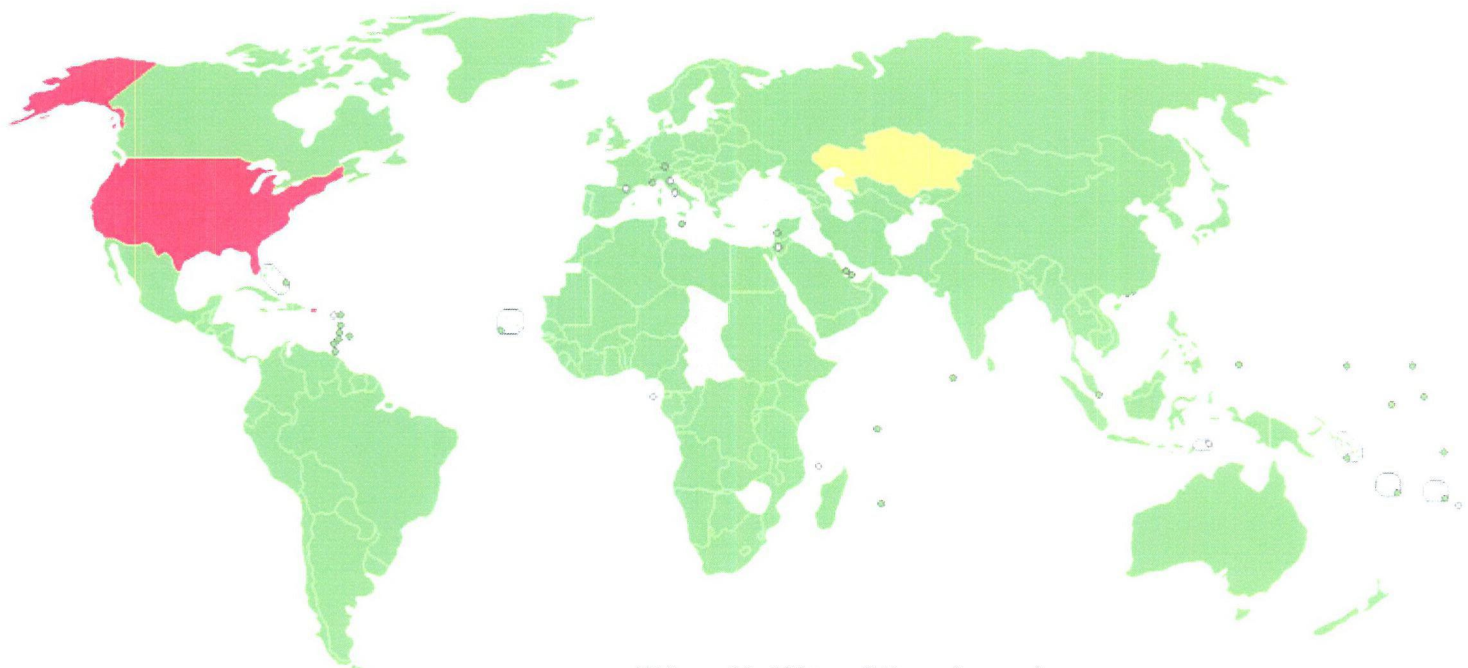
International, National, Regional, and State (California) Programs

"Kyoto Protocol"
(a.k.a. International GHG Reduction Treaty)



Developed (Annex I) countries to reduce emissions of six greenhouse gases 5.2% below 1990 levels by 2008 - 2012

Kyoto Protocol Participation



- Signed and ratified
- Signed, ratification pending
- Signed, ratification declined
- No position

Flexibility Mechanisms

- Emissions Trading
- Joint Implementation
- Clean Development Mechanism

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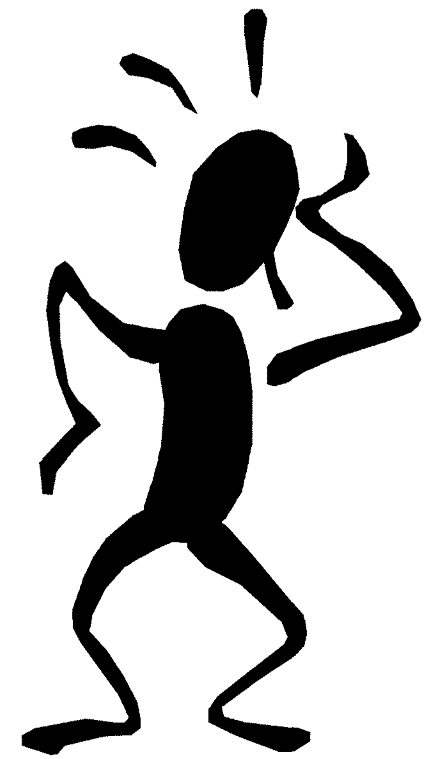
European Union ETS

- Collective commitment by 27 countries under Kyoto to achieve 8% reduction in GHG emissions from 1990 levels
- ETS to be implemented in three phases:
  - 2005-2008 – trial "warm-up" phase
  - 2008-2012 – Kyoto compliance phase
  - 2013 to 2020 – Post Kyoto commitment

European Union (EU) ETS: Lessons Learned in Phase I

- National Allocation Plans
  - Lack of accurate inventory of emissions
  - Overallocation of allowances
  - Inconsistencies in definition of "covered installation"
  - Allocations subject to political influence
- Result: Market failure CO_2 allowance prices declined from €30 to €0.1 per ton



EU ETS Lessons Learned

- Accuracy of emissions data
  - Accounting and monitoring
- Sufficient scarcity to force investments and trading
- Complexity and transparency of trading program
  - Minimization of political interference
- Time horizon for compliance
  - Banking/transition between phases
  - Early reductions and compliance planning

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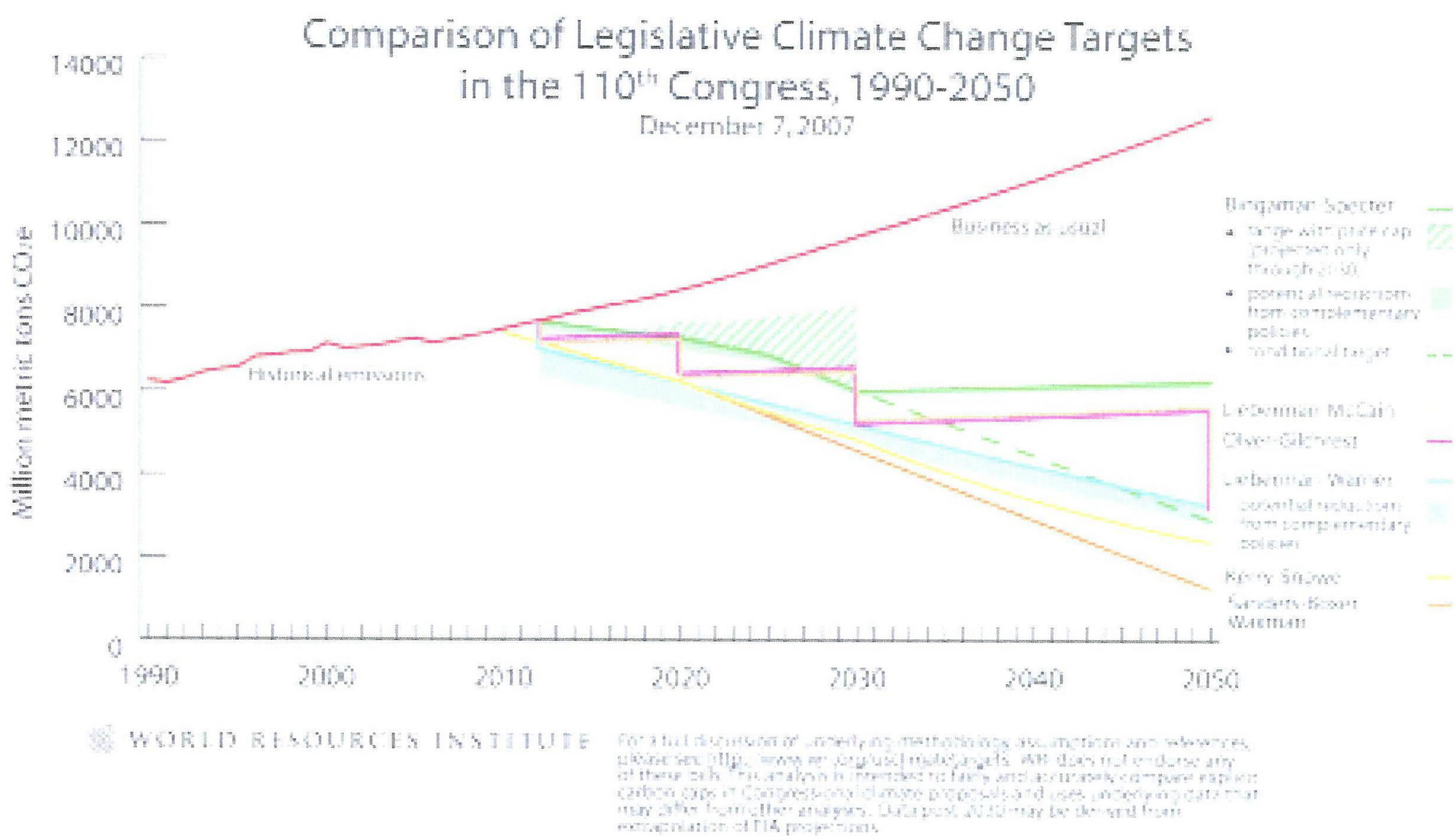
Federal GHG Legislation

- Multitude of proposed legislative bills seeking 60% - 90% reductions in GHG emissions over next three to four decades
- Key Issues/Differences
  - Carbon Tax vs. Market-Based Trading
  - Point of Regulation
  - Allocation vs. Auction of Allowances
  - Economy Safety Valve
  - Offsets
  - States Pre-emption
  - International Linkage and Developing Country Participation

Congressional GHG Bills



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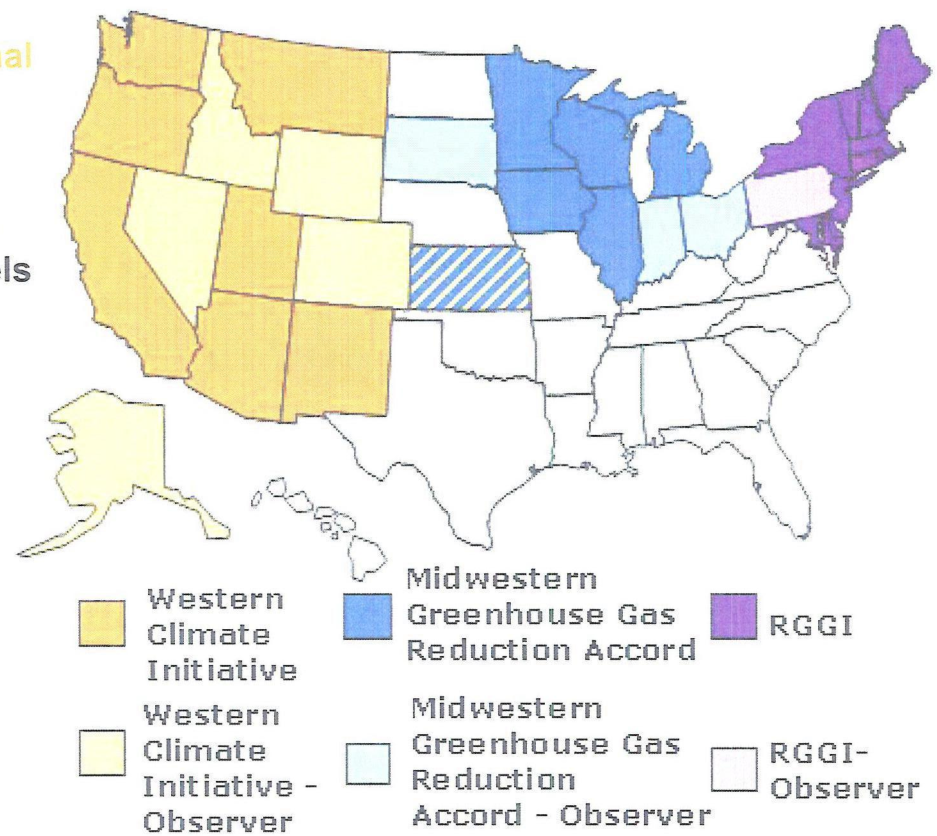
Carbon Tax

- Levy upstream on fuel's carbon content
  - Increased fuel costs pass along to increase costs of electricity and energy-intensive goods
  - Energy-saving behaviors encouraged, shift to lower carbon fuels
- Revenues used to reduce/replace other taxes (i.e., income)
- Price volatility risks and administrative burdens alleviated

Regional GHG Initiatives

Midwest GHG Reduction Accord – multi-sector reduction target 60%-80% below current levels

Western Regional Climate Action Initiative – economy-wide reductions 15% below 2005 levels by 2020



Regional GHG Initiative – caps power plant emissions in 2009, 10% reduction 2015-2019

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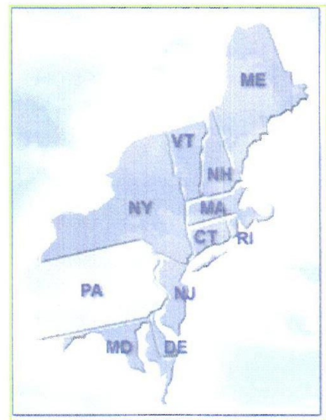
Regional GHG Initiative

Initial Auctions 2008 — September 10, 2008 and December 17, 2008

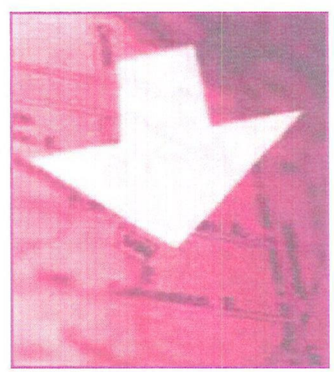
Phase 1 2009 – 2014



Stabilize Power Sector Emissions

Fossil Fuel Generators of ≥ 25 MW
188 million ton CO_2 Regional Cap
State Allocation of Allowances
3 Year Compliance Period

Phase II 2015 - 2018



Reduce Power Sector Emissions

2.5% Annual Decline

2018 — **Annual Emissions Budget 10% Smaller than 2009**

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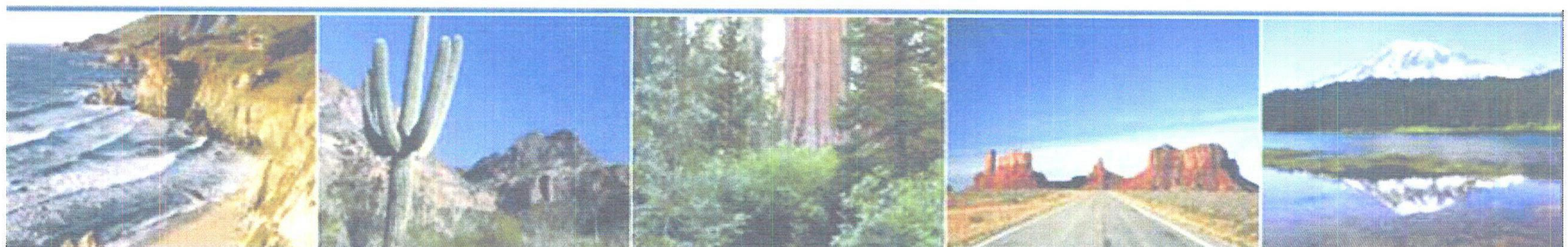
Western Climate Initiative Timeline

- January 2008 — Public Workshop to Identify Major Options
- May 2008 — Present Recommendations on Key Elements
- July 2008 — Present the Preferred Integrated Plan for Consideration
- August 2008 — Design Regional Market-Based Multi-Sector Mechanism

Goal to Establish Economy-wide Program to Achieve Aggregate Emissions Reductions of CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6 15 percent below 2005 levels by 2020



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California Global Warming Solutions Act

AB 32 Emissions Trading

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AB32 Timeline

July 1, 2007 — Early Action Measures for Implementation pre-2010 Adopted

January 1, 2008 — Mandatory GHG Emissions Reporting Adopted

During 2009 — Emission Reductions and Implementation

January 1, 2009 – Plan to be adopted for how emissions reductions will be achieved

During 2009 – Language to implement plan drafted

During 2010 — Early Action Measures Take Effect & Continued Rulemaking

January 1, 2011 — Completion of Major Rulemaking Activities

January 1, 2012 — GHG Rules & Market Mechanisms Take Effect

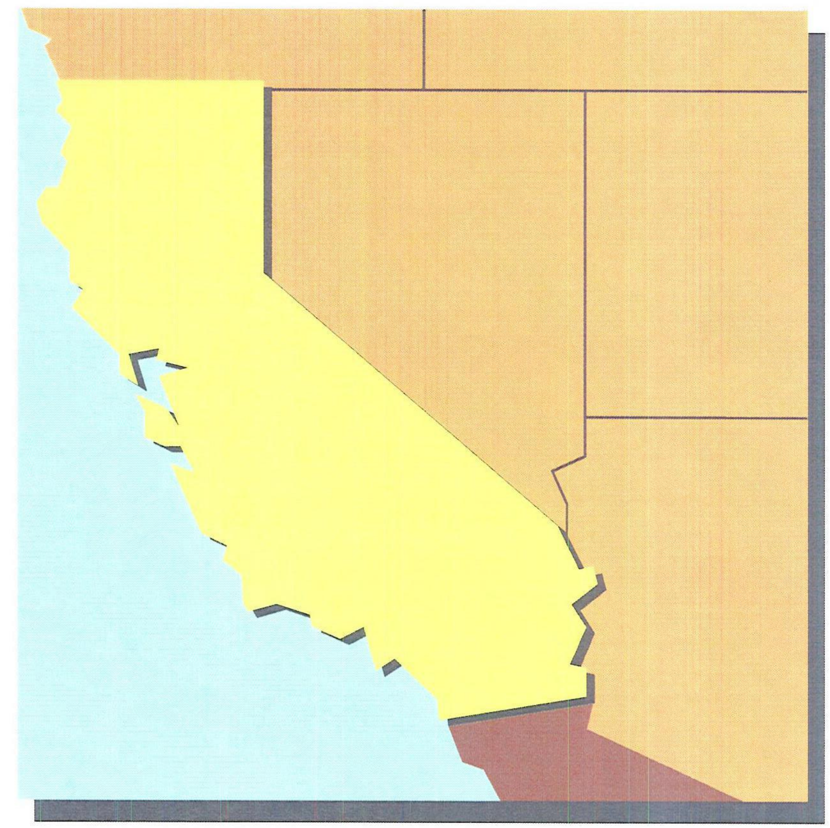
December 31, 2020 — Deadline for Achieving 2020 GHG Emissions Cap

Electricity Sector Point of Regulation

- Retail Providers
- Deliverer / First Seller
- In-State Generators
- Hybrid Retail/Generator

CA Trading Program - Elements and Considerations

- Distribution of Allowances
  - Allocation vs. Auction
  - Timing and Frequency
- New Entrants
- Safety Valve
- Offsets
- Early Actions



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CPUC/CEC Electricity Sector Recommendations

- Scope plan requirements at level of all cost-effective energy efficiency in the State
- Go beyond 20% renewable energy
- Move forward with multi-sector cap and trade system that includes electricity sector
  - Deliverers of electricity as point of regulation
  - Mix of allocation and auctioning of allowances

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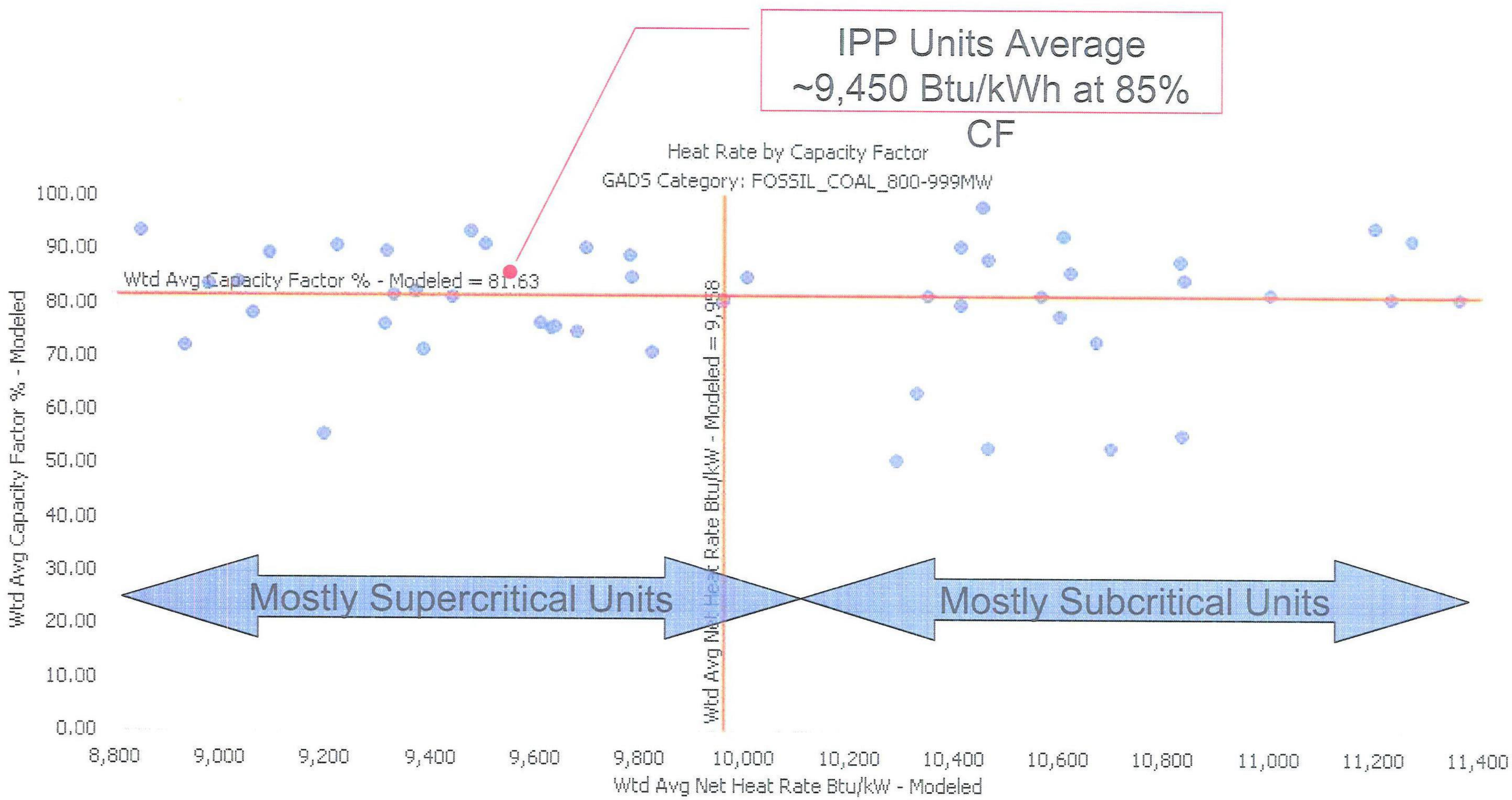
Task 1
IPP Efficiency Improvements

Approach to Task 1

- Design and Operating Data Collection
- 2 Day Site Visit; 32 Projects Identified
- 32 Projects Screened and Categorized
  - Capital Improvements
  - Maintenance Repair/Replace Strategies
  - Operations Support Systems
  - Operations Practices (not considered)
- Net Benefit Analysis of 18 Projects (@ $20 and $40 per ton)
- Project Report and Presentation

IPP – Limited Heat Rate Reduction Opportunity



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Maximum CO_2 Reduction Opportunity (@ $40/ton)

- 32,000 ton/yr from Currently Planned Projects

+

- 142,000 ton/yr with a Capital Cost of $45.5M

=

- 172,000 ton/yr
- Rate reduced from 1,950 to 1,925 lb_m/MWh (1.3%)
- 3% of the way to the benchmark of 1,100 lb_m/MWh

Six Planned Projects

- 32,000 ton/yr from Currently Planned Projects

Project Description	CO_2 Reduction (ton/yr)
Closed Loop Combustion Optimization System	18,719
Cooling Tower Modifications (Further study required)	0
Replace Primary AH Baskets (Benefit incl in #21 PA Seals)	0
Generator Rewind	3,704
Compressed Air Audit & Repair/Replacement	5,141
Modify Pulverizers w/ Rotating throat and Static Classifiers	4,445
Total	32,008

Eight New Projects Viable @ \$40/ton CO_2 Cost

- 142,000 ton/yr with a Capital Cost of \$45.5M

Project Description	Est Capital Cost	CO_2 Reduction (ton/yr)	CO_2 Benefit (\$/yr)	Heat Rate Reduction (Btu/kWh)	Heat Rate Benefit (\$/yr)	Aux load benefit (MW)	Net Benefit (\$/yr)	Breakeven Cost (\$/tonCO_2)
Modification of PA Air Heater Sector Plates and Installation of Duplex Sealing System	\$418,000	26,501	\$1,060,036	6	\$423,495	2.40	\$1,457,575	\$0
Upgrade IPT Steam Path	\$13,333,000	41,597	\$1,663,874	29	\$664,735	0.00	\$1,273,714	\$0
Sliding Pressure Operation	\$0	14,798	\$591,922	10	\$236,479	0.00	\$832,580	\$10
VFD Motor for Condensate Pumps	\$1,312,000	7,734	\$309,341	0	\$123,585	1.04	\$330,149	\$0
Cycle Isolation Audit & Valve Repair/Replacement	\$120,000	4,160	\$166,387	3	\$66,473	0.00	\$224,435	\$0
LP Turbine Upgrade One Hood	\$27,000,000	40,706	\$1,628,237	28	\$650,497	0.00	\$130,229	\$29
Upgrade BFPT (Blades and Seals)	\$2,000,000	4,245	\$169,802	3	\$67,838	0.00	\$78,838	\$22
High Efficiency Motor for Coal Pulverizers	\$1,360,000	2,422	\$96,891	0	\$38,709	0.33	\$27,484	\$37
Summary Total *(Net Benefit >0 Only)*	**\$45,543,000**	**142,162**	**\$5,686,491**	**79**	**\$2,271,811**	**3.8**	**\$4,355,006**	

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Five New Projects Viable @ $20/ton CO_2 Cost

- 95,000 ton/yr with a Capital Cost of $15.2M

Project Description	Est Capital Cost	CO_2 Reduction (ton/yr)	CO_2 Benefit ($/yr)	Heat Rate Reduction (Btu/kWh)	Heat Rate Benefit ($/yr)	Aux load benefit (MW)	Net Benefit ($/yr)	Breakeven Cost ($/ton$CO_2$)
Modification of PA Air Heater Sector Plates and Installation of Duplex Sealing System	$418,000	26,501	$530,018	6	$423,495	2.40	$927,557	$0
Upgrade IPT Steam Path	$13,333,000	41,597	$831,937	29	$664,735	0.00	$441,777	$0
Sliding Pressure Operation	$0	14,798	$295,961	10	$236,479	0.00	$536,619	$10
VFD Motor for Condensate Pumps	$1,312,000	7,734	$154,670	0	$123,585	1.04	$175,479	$0
Cycle Isolation Audit & Valve Repair/Replacement	$120,000	4,160	$83,194	3	$66,473	0.00	$141,242	$0
~~Upgrade BFPT (Blades and Seals)~~	~~$2,000,000~~	~~4,245~~	~~$84,901~~	~~3~~	~~$67,838~~	~~0.00~~	~~-$6,063~~	~~$22~~
~~High Efficiency Motor for Coal Pulverizers~~	~~$1,360,000~~	~~2,422~~	~~$48,446~~	~~0~~	~~$38,709~~	~~0.33~~	~~-$20,961~~	~~$37~~
~~LP Turbine Upgrade One Hood~~	~~$27,000,000~~	~~40,706~~	~~$814,119~~	~~28~~	~~$650,497~~	~~0.00~~	~~-$683,890~~	~~$29~~
Summary Total *(Net Benefit >0 Only)*	**$15,183,000**	**94,789**	**$1,895,780**	**48**	**$1,514,767**	**3.4**	**$2,222,674**	

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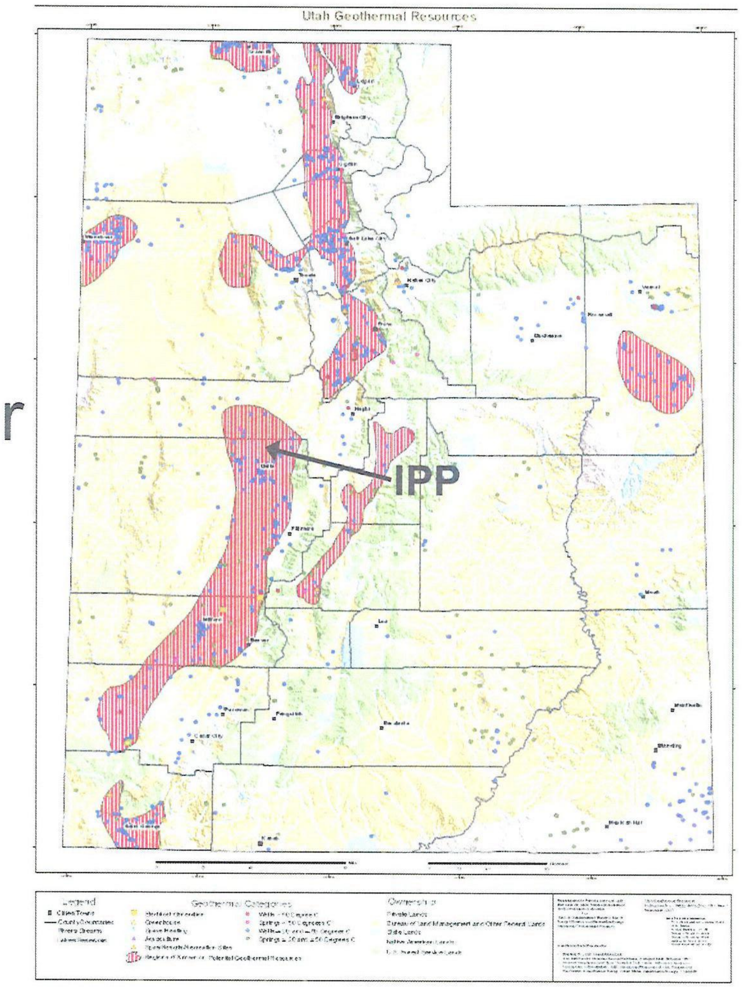
Tasks 2 and 6
Renewable Resources

Renewable Energy Options

- Geothermal feedwater heating
- Geothermal power
- Solar thermal feedwater heating
- Solar thermal power
- Wind
- Hydro
- Co-firing – both biomass and natural gas

Geothermal

- IPP lies in a promising geothermal area
- B&V analyzed the potential for
  - Geothermal feedwater heating
  - Stand-alone geothermal power generation



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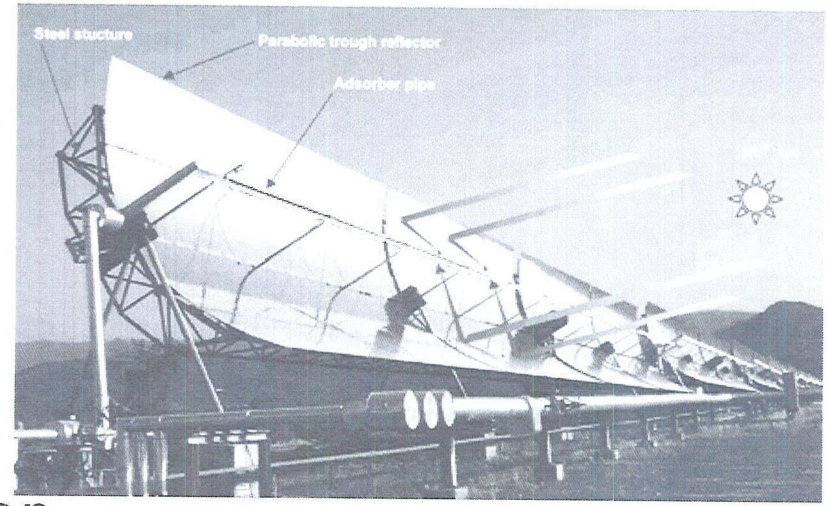
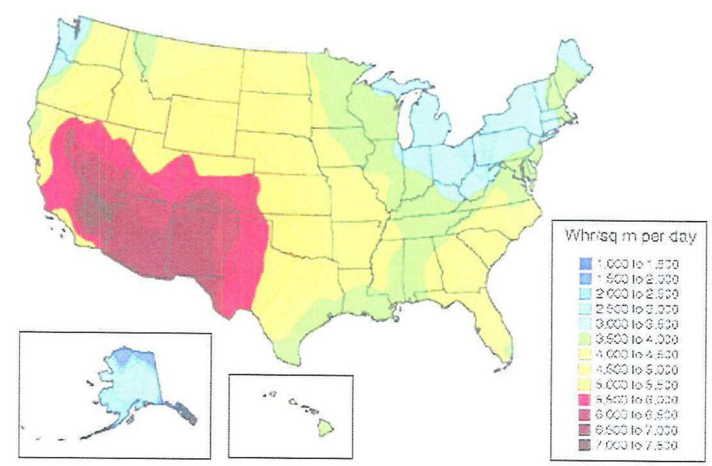
Geothermal

- Geothermal resource near IPP does not have sufficient temperature/flow rate to be thermodynamically feasible for feedwater heating
- One identified area is feasible for geothermal power production (binary cycle)
  - May already be under development by Raser Technologies

Solar



- B&V analyzed the potential for
  - Solar thermal feedwater heating
  - Stand-alone solar thermal power generation
- Assumed parabolic trough technology



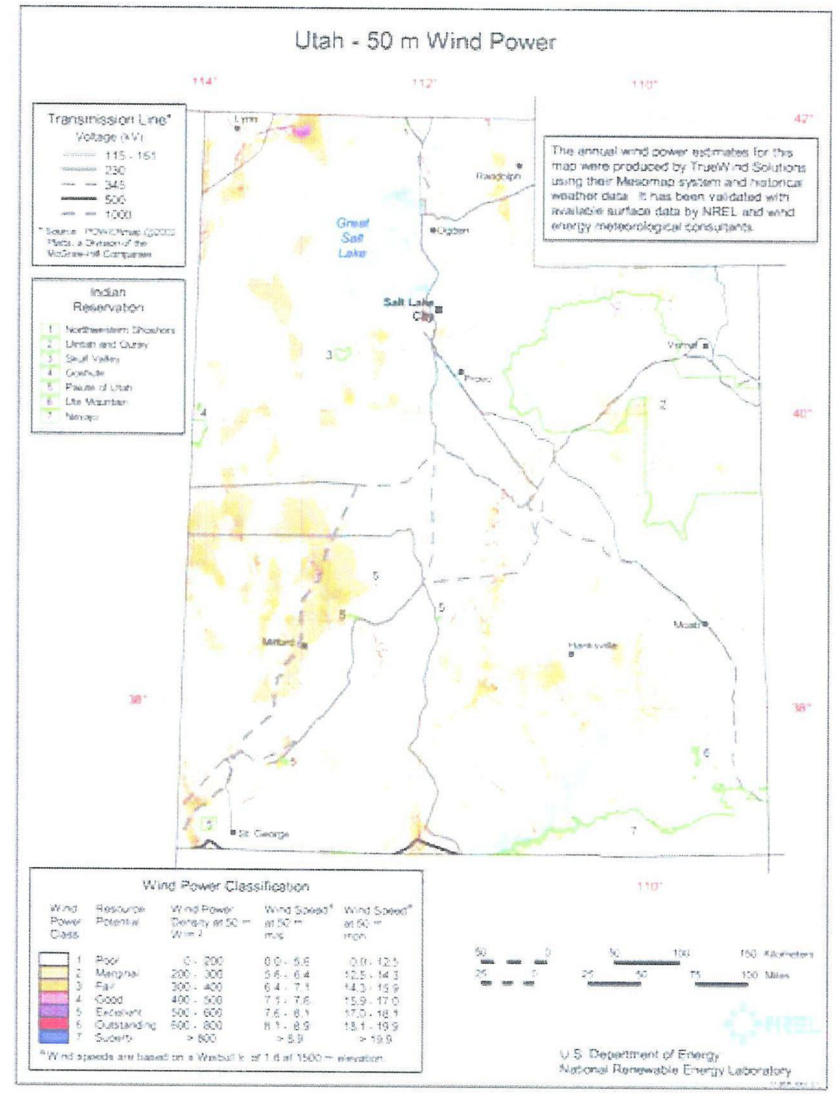
Solar resource for a concentrating collector

Solar

- Solar thermal feedwater heating
  - Hot working fluid heats feedwater, reducing extraction steam needed
  - Solar field would be located near IPP
- Solar thermal electric
  - Complete power block required
  - Solar fields located in area of flat terrain near transmission

Wind

- Limited wind resources around IPP, mostly along ridgelines
- Best opportunities near the IPP-Gonder transmission line towards Nevada
- Intermittent resource (CF ≈ 29%)



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Hydro

- Limited hydro opportunities
- Best potential site is the upper Sevier River
- Significant opposition to development would be expected

Others

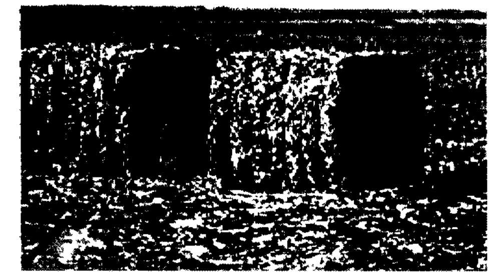
- Small potential for anaerobic digestion and landfill gas
  - AD potential for 5 to 8 MW
  - Further study needed to quantify cost and potential
  - Not known if methane reduction credits are eligible
- Minimal potential for landfill gas

Summary

Renewable Energy Options Comparison.					
Option	**Near-Term Lev. Cost of CO_2 Reduction (\$/ton)**	**Near-Term Potential CO_2 Reduction (ton/yr)**	**First Year Available**	**Near-Term Percent IPP CO_2 Reduction**	**Long-Term Percent IPP CO_2 Reduction**
Geothermal Power	136	102,000 *(Capacity = 15 MW)*	2012	0.7%	0.7%
Solar Power	230	186,000 *(Capacity = 100 MW)*	2012	1.3%	13.0%
Solar Feedwater Heating	135	104,000 *(Capacity = 50 MW)*	2010	0.7%	1.5 to 3.0%
Wind	91	988,000 *(Capacity = 400 MW)*	2011	7.0%	21.2%
Hydro	111	64,000 *(Capacity = 15 MW)*	2013	0.5%	0.8%

Alternative Fuels

- Looked at four different co-firing options:
  - 1% (direct blend)
  - 10% (separate injection)
  - 20% (new burners installed)
  - 10% natural gas (new igniters installed)



Alternative Fuels

Alternative Fuel Quantities.		
	Heat Input (MBtu/yr)*	**Approximate Quantity**
1% biomass	1,406,000	220,000 wet tons/yr
10% biomass	14,130,000	2,100,000 wet tons/yr
20% biomass	28,490,000	4,100,000 wet tons/yr
10% natural gas	14,160,000	13,800 million standard cubic feet (scf)/yr

* Based on average IPP generation from 2006 and 2007. Considers Net Plant Heat Rate reduction that occurs by co-firing alternative fuels with coal.

Alternative Fuels

Co-Firing Options Comparison (With CO_2 Penalty).						
	Levelized Cost of CO_2 Reduction ($/ton)		Potential CO_2 Reduction (ton/yr)		Percent IPP CO_2 Reduction	
	With CO_2Penalty	Without CO_2 Penalty	With CO_2Penalty	Without CO_2 Penalty	With CO_2Penalty	Without CO_2 Penalty
1% Biomass	41	35	124,000	146,000	0.9%	1.0%
10% Biomass	69	48	1,020,000	1,460,000	7.5%	10.0%
20% Biomass	80	48	1,750,000	2,900,000	12.0%	20.0%
10% Natural Gas	75	75	496,000	496,000	3.5%	3.5%

Note: Penalty accounts for the CO_2 emitted during the harvesting, processing, and transportation of biomass fuels, as required under CA Senate Bill 1368, section 8341.

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Tasks 3 and 4
Carbon Capture and Sequestration

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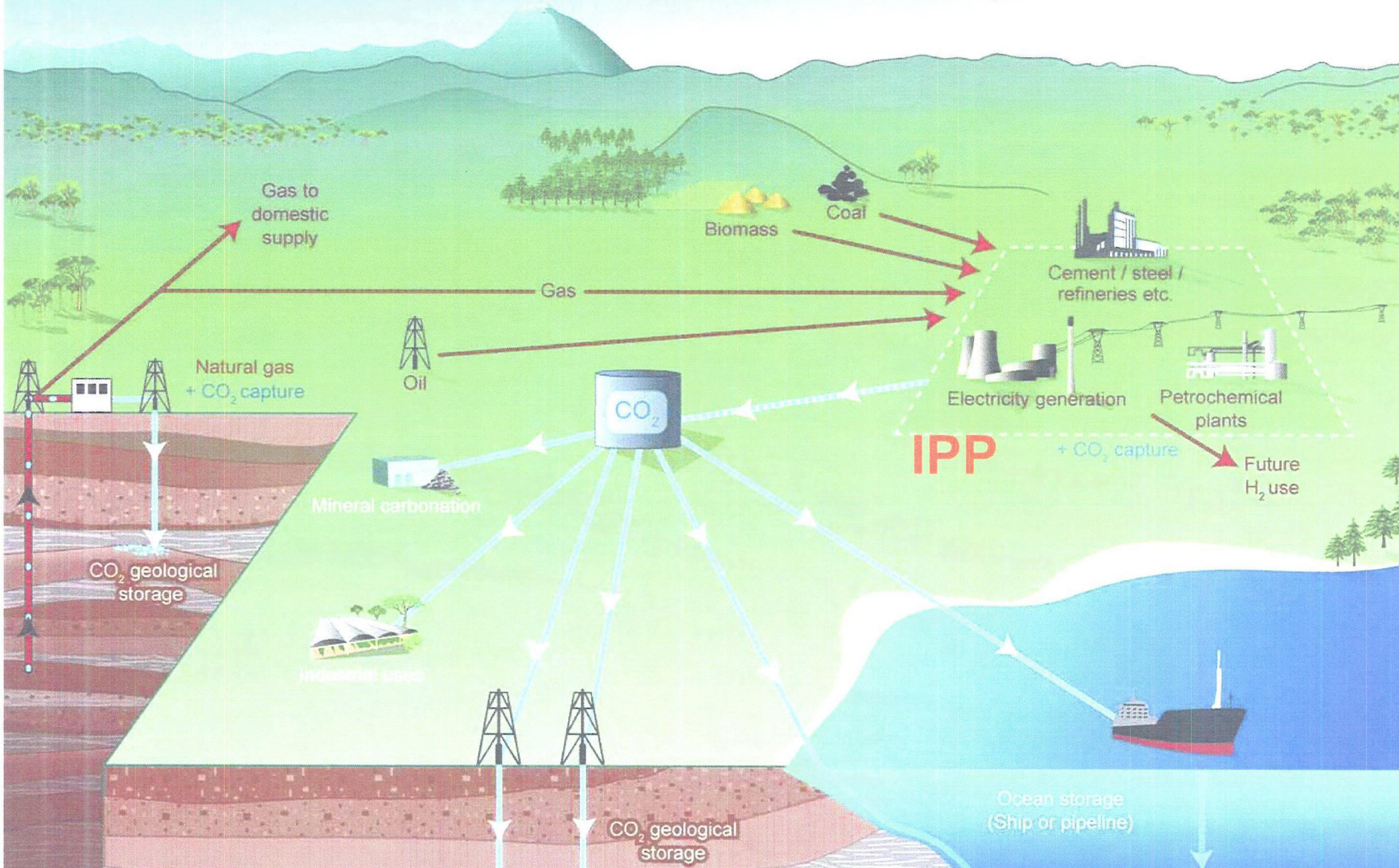
Schematic diagram of possible CCS systems



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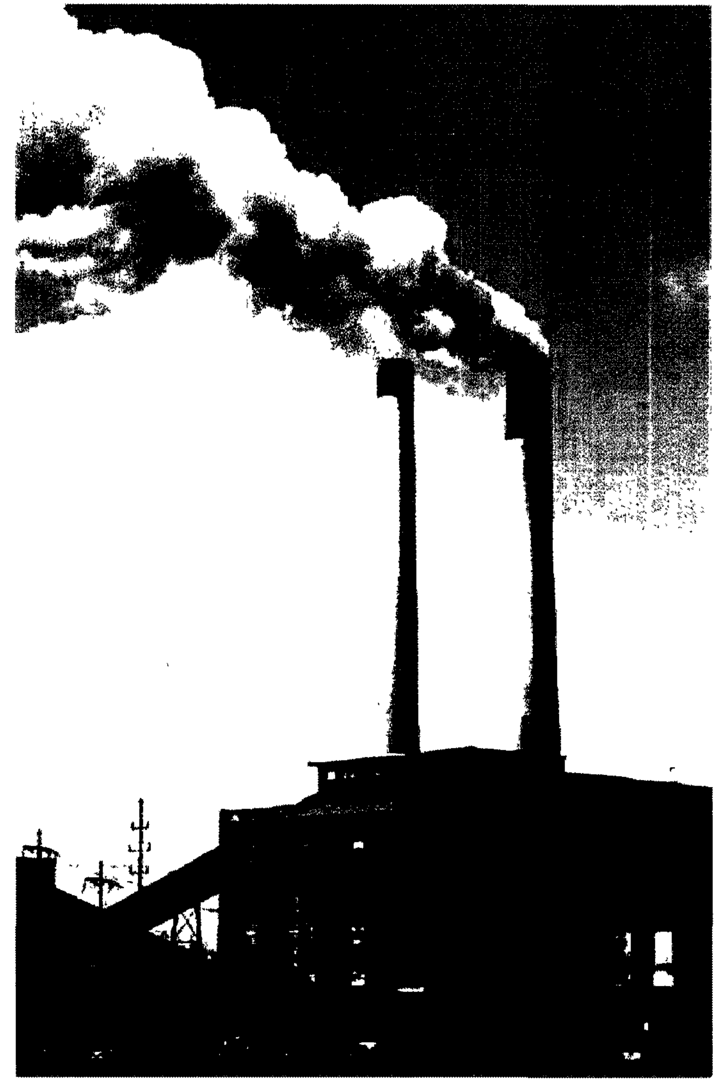
Carbon Dioxide Capture and Storage Project Life Cycle Stages

CAPTURE	TRANSPORT	INJECTION AND STORAGE
Pre- or Post- Combustion Exhaust Gas Removal and Compression →	Delivery from Capture Source to Injection Well →	Subsurface Injection Storage and Long-Term Stewardship
Capture Project	**Transport Project**	**Injection and Storage Project**
Stationary Source Siting, Permitting and Operation	Pipeline Routing, Permitting and Operation	Site Characterization, Permitting, Operation and Closure

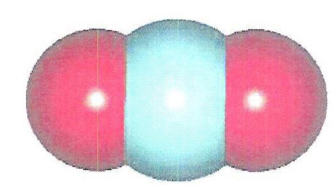
CO_2 Capture in Power Plants



- Available technologies exist for capturing CO_2 from fossil power plants
- Several unproven technologies show promise
- No US power plants currently capturing significant percentage (>15%) of CO_2 generated
- Costs to capture CO_2 are high for all processes

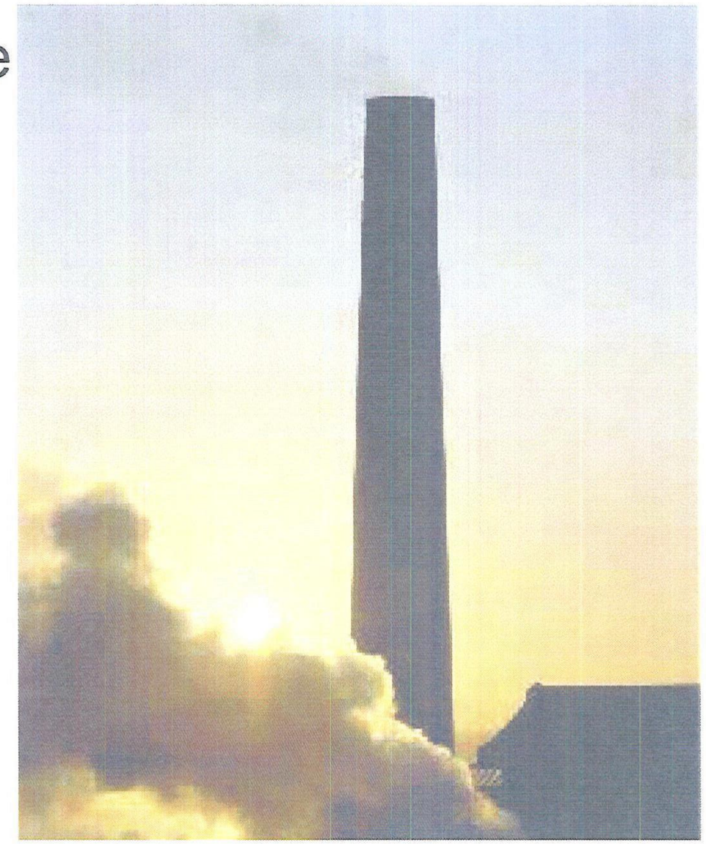
Three Categories of Capture Processes

- Post-Combustion Capture
  - Large volumes of flue gas and CO_2
  - Processes not proven at scale
- Pre-Combustion Capture
  - IGCC
- Oxy-Fuel Combustion
  - Not Considered Further

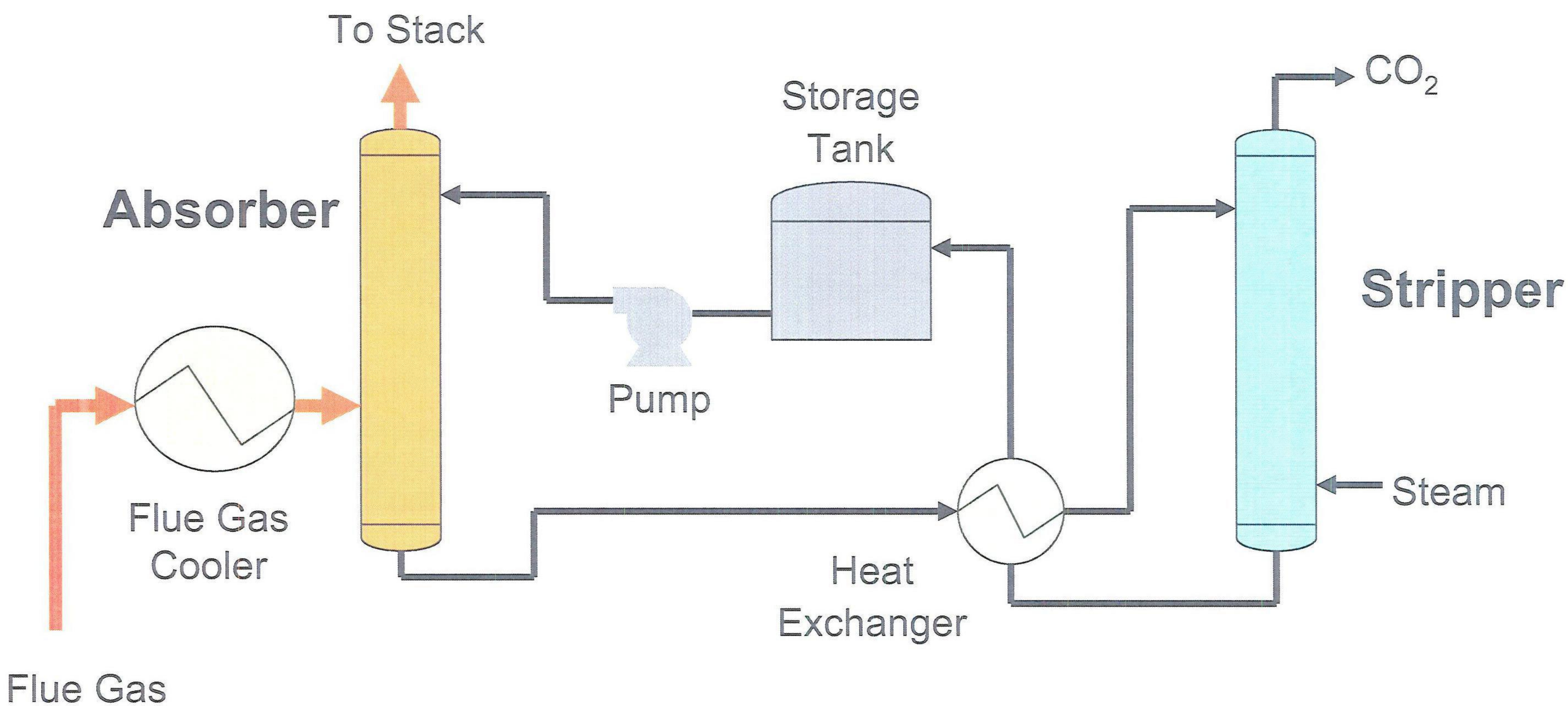


Post-Combustion Processes

- **Amine solvent**
  - Proven technology at smaller scale
  - Chemical solvent, typically monoethanolamine (MEA)
- **Ammonia solvent**
  - Similar configuration to amine



Simplified Post-Combustion Process



Chilled Ammonia Solution

NH_3

- Technology under development by Alstom and EPRI
- Similar to amine absorber/stripper, but operates at lower temperature
- Flue gas chilled to 32-50° F for high capture efficiency and low NH_3 emission
- Chilling flue gas also reduces volume and increases CO_2 concentration (due to H_2O removal)
- 1.7 MW pilot scale plant at We Energies Pleasant Prairie Station (2008 Operation)
- AEP and Alstom announced plans to install 10 MW pilot at Mountaineer Plant in W. Va.

Amine and Ammonia Performance Comparison

IPP Performance Estimate for CO_2 Capture.		
	Amine	**Ammonia**
Flue Gas to CO_2 Capture, percent	68	70
CO_2 in Flue Gas from Power Plant, tons per hour (tph)	1,755	1,755
CO_2 Captured, tph	958	996
CO_2 Captured, percent	54.6	56.8
CO_2 to Atmosphere, tph	797	759
Net Power without CO_2 Capture, MW	1,800	1,800
Net Power from PC Units with CO_2 Capture, MW	1,460	1,387
CO_2 emitted, pounds per megawatt-hour (lb/MWh)	1,092	1,094
Additional Cooling Water Makeup from River, gallons per minute (gpm)	4,260	2,252

Amine and Ammonia Cost Comparison

Capital and Operating Costs (2008 US$).

	Amine	Ammonia
CCC Direct Capital Cost ($million)	1,400	1,300
CO_2 Transport Direct Cost ($million)	470	470
Total Direct Cost ($million)	1,870	1,770
Owner's Cost at 40% of Direct ($million)	748	708
Total Capital Cost ($million)	2,618	2,478
O&M Cost		
Fixed ($million/year)	2	2
Variable ($million/year)	29.2	37.5

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Risks and Liabilities

Key issues and challenges of CCS regulation

- Ecological and health safety risks
- Regulatory agencies' jurisdiction
- Classification of CO_2
- Ownership and property rights
- Long-term post-closure assurance
- Public acceptance

Human health and ecological risks

Health Risks

- No physiological effects up to 1% (10,000 ppm)
- 1 – 3% adaptation
- 3 – 5% respiratory rate and discomfort
- > 5% impairment of physical and mental abilities, loss of consciousness
- > 10% rapid loss of consciousness, coma, death

Ecological Risks

- Minimal impacts from small scale, short-term gas leaks
- Persistent leaks could suppress respiration in root zone, result in soil acidification, lower pH in aquatic ecosystems
- Catastrophic releases (20-30%) can kill vegetation and animals

Regulatory agencies' jurisdictions

Different federal, state, and local agencies responsible for ensuring materials are captured, handled, transported, injected, and stored in a safe and appropriate manner

Federal Agencies

- Environmental Protection Agency
- DOT Office of Pipeline Safety
- Minerals Management Service
- Occupational Safety and Health Administration

State Agencies

- Public Utility and Oil & Gas Commissions
- Environmental & Natural Resource Agency
- Department of Transportation

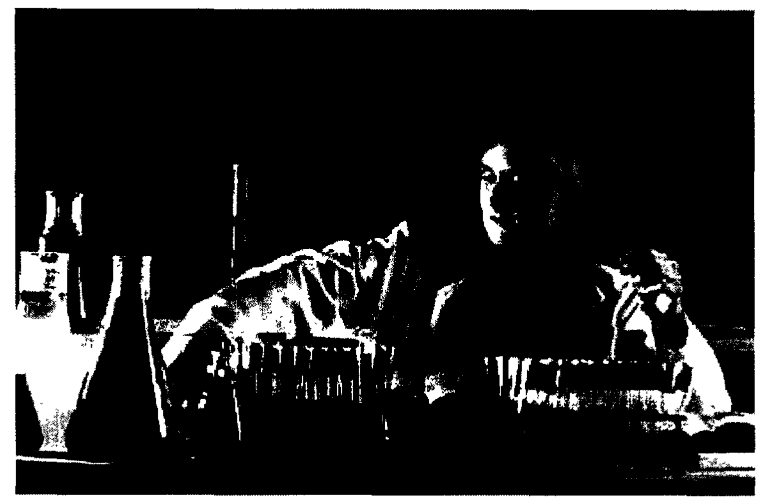
Local Authorities

- Planning & Zoning

Key issues and challenges

Classification of CO_2

- Commodity
- Pollutant
- Waste
- Hazardous / Dangerous
- Non-hazardous



Key Issues & Challenges

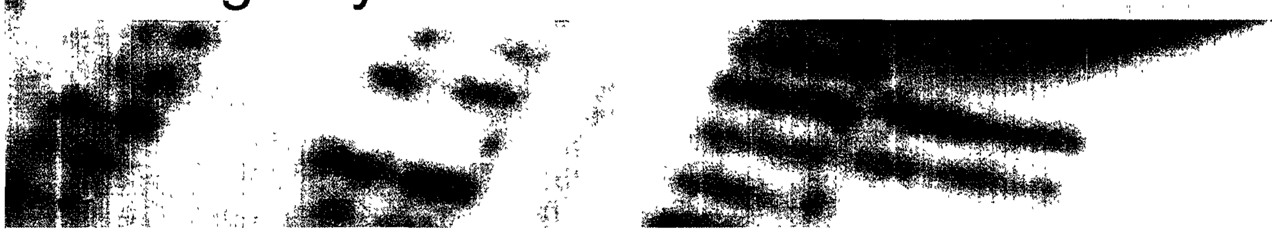
Ownership and Property Rights

- Surface
  - Access
  - Easements
- Subsurface
  - Minerals
  - Formations
  - Pore space

- Personal property
  - CO_2
  - Credits
- Legal Doctrines
  - Capture
  - Eminent Domain
  - Injuries and Damages

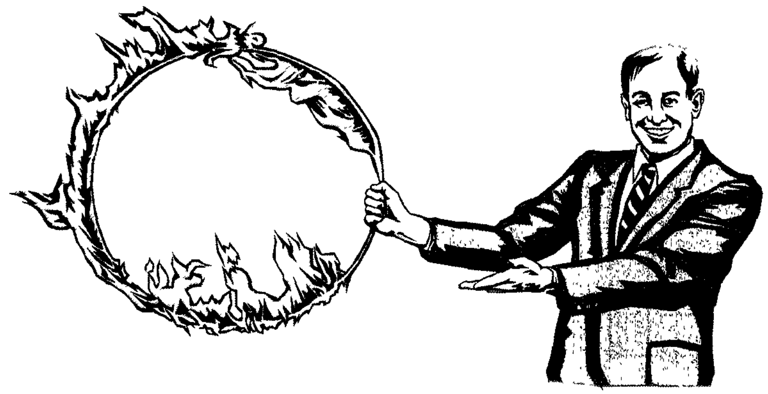
Long-term post-closure assurance

- Intergenerational regulation
- Transfer long-term risk liability to government / public
- Responsibility for orphaned sites
- Monitoring for migration and leakage
- Accidental release liability and remediation
- Global risks of leakage and releases
- Longevity of institutions and transfer of knowledge



Public acceptance

- Demonstration and confidence in geologic sequestration
- NIMBY / NUMBY issues:
  - Decrease in property values
  - Environmental justice
  - Accidents and safety hazards



- Level and role of public and NGO participation in siting and permitting
- Continued acceptance of costs and risks over time

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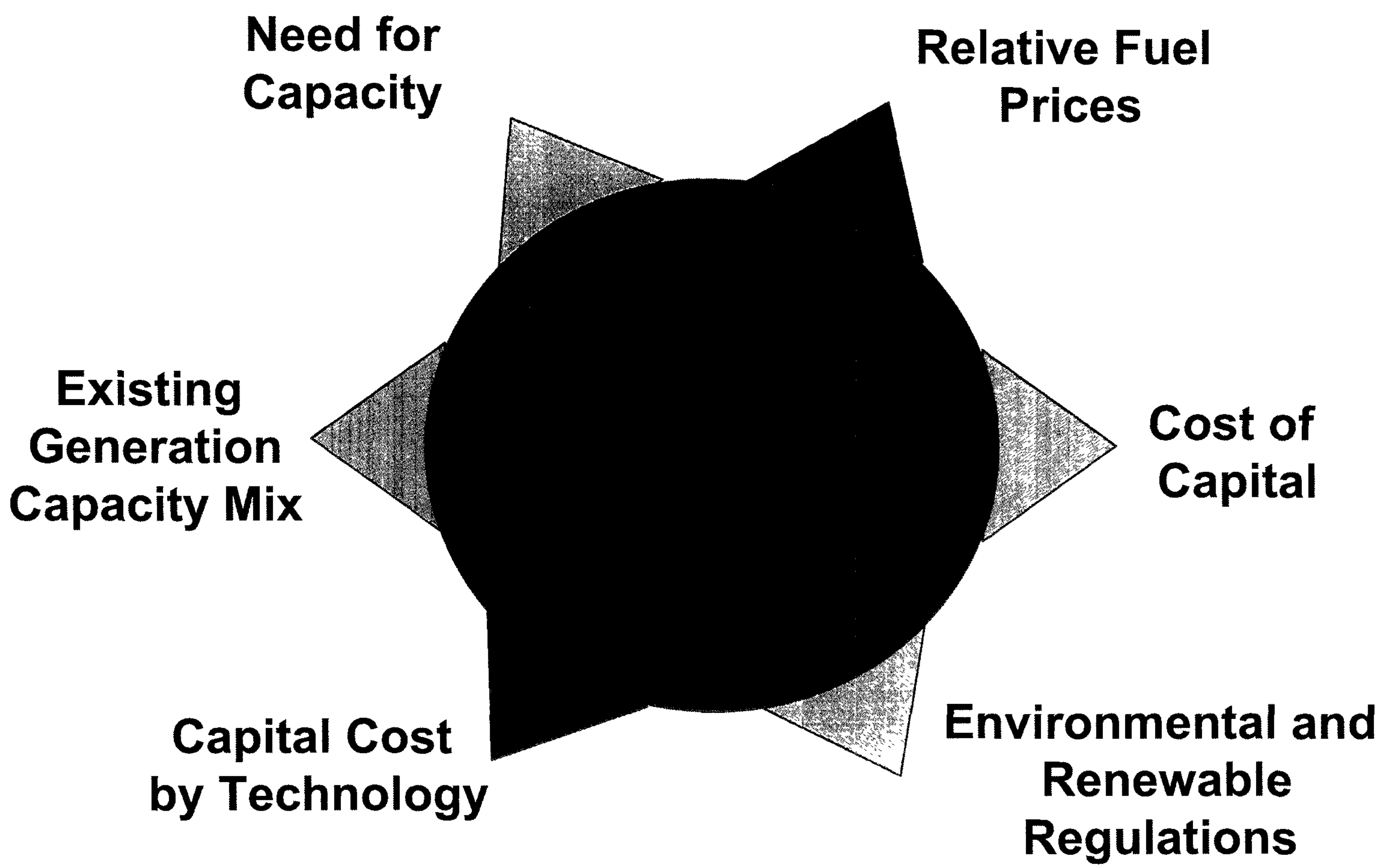
Task 5
Economic Impacts of CO_2 Cap and Trade Programs

Lieberman-Warner
Western Climate Initiative
AB 32

Key drivers for baseline generation additions



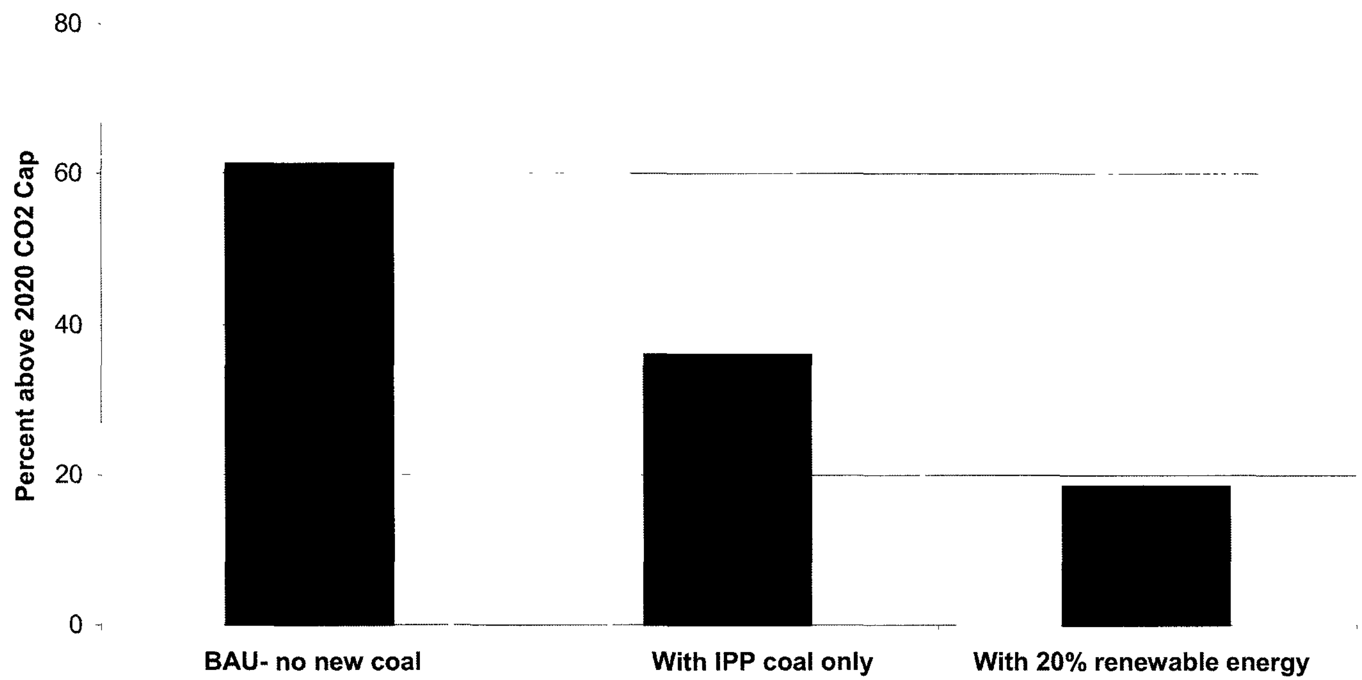
IPP May Control CO_2 or Purchase Allowances

- Economically, IPP should control emissions only to the point where the incremental cost of CO_2 control reaches the price of CO_2 allowances
- The price of allowances in a cap and trade program should be based on the cost of control by the last generator that makes the region meet its cap – *markets induce marginal cost-based pricing*
- Cap and trade induces use of least-cost CO_2 control measures first
- The price of allowances is a direct function of the cap level and the cost of control for all the generators in the trading area

CO_2 avoidance / abatement alternatives

- New combined cycle capacity in place of new coal capacity
- New combined cycle capacity coupled with wind generation in place of new coal capacity
- New nuclear capacity in place of new coal capacity
- IGCC capacity with capture and sequestration in place of new coal capacity
- New combined cycle capacity to replace existing inefficient coal generation
- Combined cycle capacity dispatches ahead of existing coal capacity reducing coal capacity factors
- Post-combustion control of existing PC capacity
- IGCC with capture in place of new combined cycle capacity

CA – What abatement measures will be needed?



BAU – Business as usual with 11% renewables

Assuming all current domestic and imported coal except for IPP is replaced by gas generation, and renewable generation is increased to 20%, results in CO_2 emissions 19% above the AB 32 cap proposed for 2020.

Implications for IPP

- If AB 32 remains the only program applicable to IPP, it may want to consider taking actions that cost less than approximately $40 per ton to remove CO_2
- Implementation of the WCI may reduce the price of CO_2 allowances but only slightly
- If the Lieberman-Warner bill is enacted with currently proposed caps, the price of CO_2 allowances is likely to cause IPP to consider adding carbon capture and sequestration
- In all cases, there will likely be pressure to increasingly cycle IPP as combined cycle generators start dispatching ahead of it due to the cost of CO_2

Summary

Comparison of Levelized Cost of CO_2

	Scenario	Capital Cost ($1000)	Operating Cost ($1000/yr)	CO2 Reduction (tons/year)	Levelized Cost of CO2 ($/ton CO2)
1	Modification of PA Air Heater and Seals	418	-	26,501	0
1	Sliding Pressure Operation	0	-	14,798	0
1	VFD Motor for Condensate Pumps	1,312	-	7,734	0
1	Cycle Isolation Audit and Valve Repair/Replacement	120	-	4,160	0
1	Upgrade IPT Steam Path	13,333	-	41,597	10
1	Upgrade BFPT (Blades and Seals)	2,000	-	4,245	22
1	"High Efficiency Motor for Coal Pulverizers"	1,360	-	2,422	29
1	LP Turbine Upgrade One Hood	27,000	-	40,706	37
2	1 Percent Biomass	1,206	1,100	124,000	41
4	Amine CO2 Scrubbing	2,619,000	31,200	7,972,000	59
4	Ammonia CO2 Scrubbing	2,479,000	37,500	8,289,000	63
2	10 Percent Biomass	314,280	1,300	1,020,000	69
2	10 Percent Natural Gas	17,640	1,100	496,000	75
2	20 Percent Biomass	549,720	1,610	1,750,000	80
6	Wind	800,000	20,700	988,000	91
6	Hydro	42,520	550	64,000	111
6	Solar Feedwater Heating	135,000	2,900	104,000	135
6	Geothermal Power	76,500	6,100	102,000	136
6	Solar Power	420,000	5,800	186,000	230

Conclusions

- Some efficiency improvements appear to be viable regardless of CO_2 reduction requirements
- Efficiency improvements do not have a significant impact on CO_2 emissions
- Only CCS and/or carbon trading have the capability to reach the target of 1,100 lb/MWh
- Carbon trading programs with CO_2 costs at <~$60/ton will provide a better option than CCS
- ***SCREENING LEVEL ANALYSIS ONLY***

Key Results and Conclusions

- IPP is a Best-in-Class Facility
- GHG ETS Not Fully Defined
- Significant Reductions of CO_2 from IPP Require CCS
  - Large Scale Capture Ready 2012-2015
  - Large Scale Sequestration Ready 2015-2020
- Viable Projects Available Today to Lower GHG Footprint

Availability Improvement Project

January 2007

IPSC

INTERMOUNTAIN POWER SERVICE CORPORATION

IP12_000200

Project Objectives

- Identify High Impact Systems
- Condition Monitoring
- Review Maintenance Methods & Pr
- Ensure Critical Parts Are Availabl
- Plan for Future Renewals & Repla

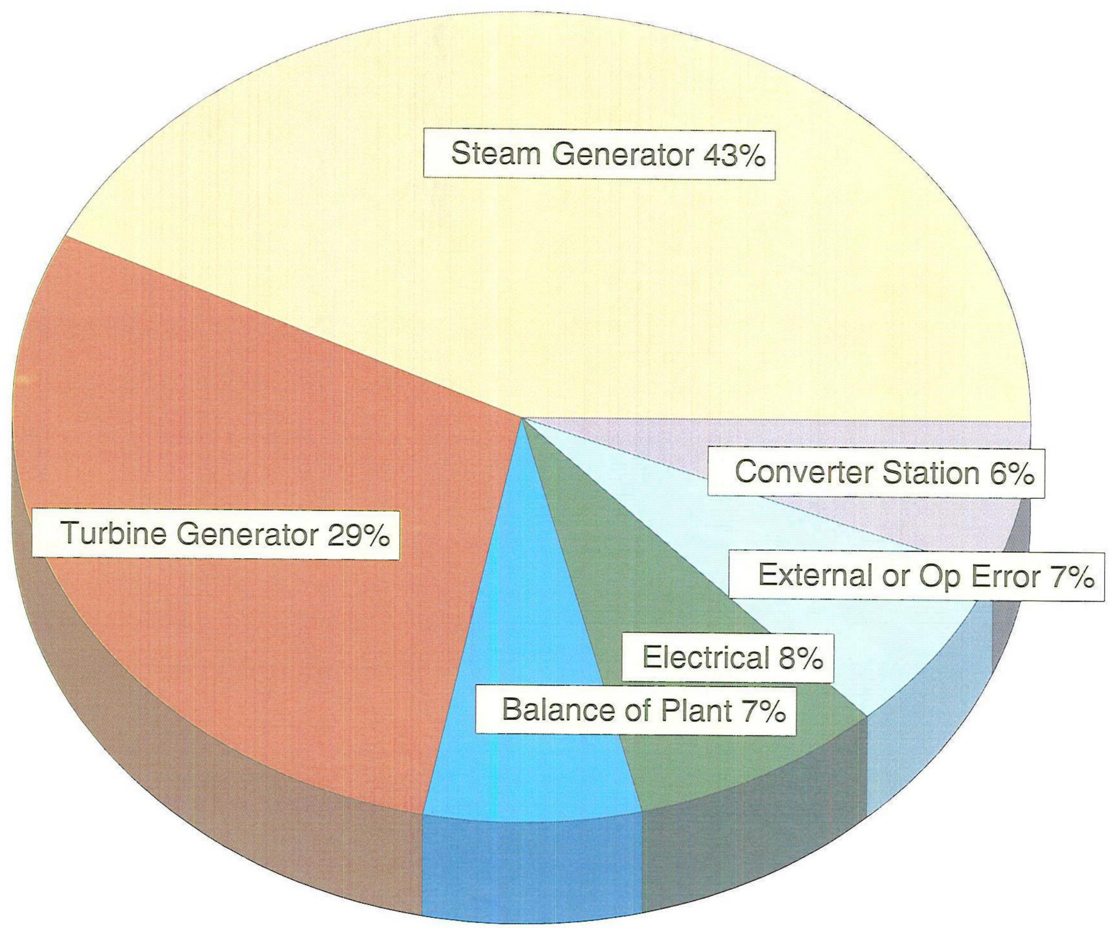
Project Methods

- Review and Categorize Event Hist
- Hold Initial Availability Improvem Meetings for Each Plant Area
- Analyze and Track Suggestions – and Accountability
- Continue Availability Improvement As-Needed.

<u>Only First Two Steps Complete</u>

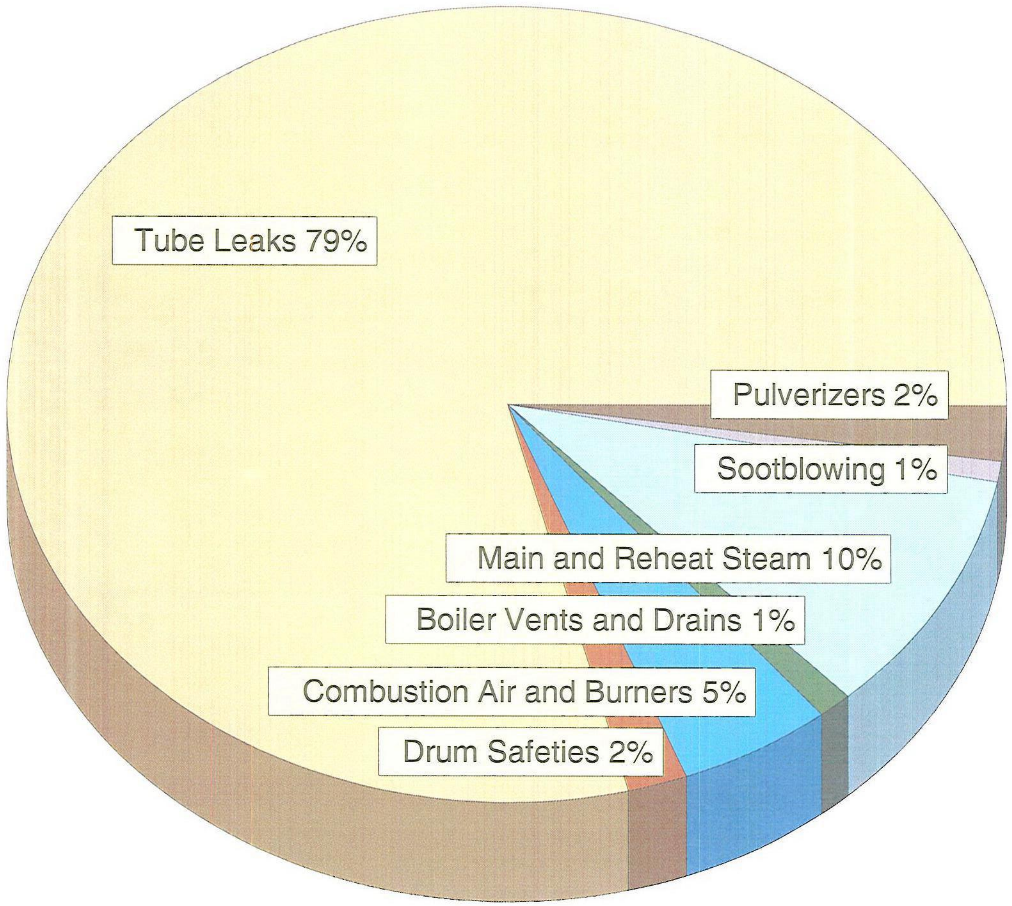
Availability Losses

Percentage of All EA Hours Lost



Steam Generator

Percentage of All EA Losses (hours) for SG Sy:



266 (29%) All Events

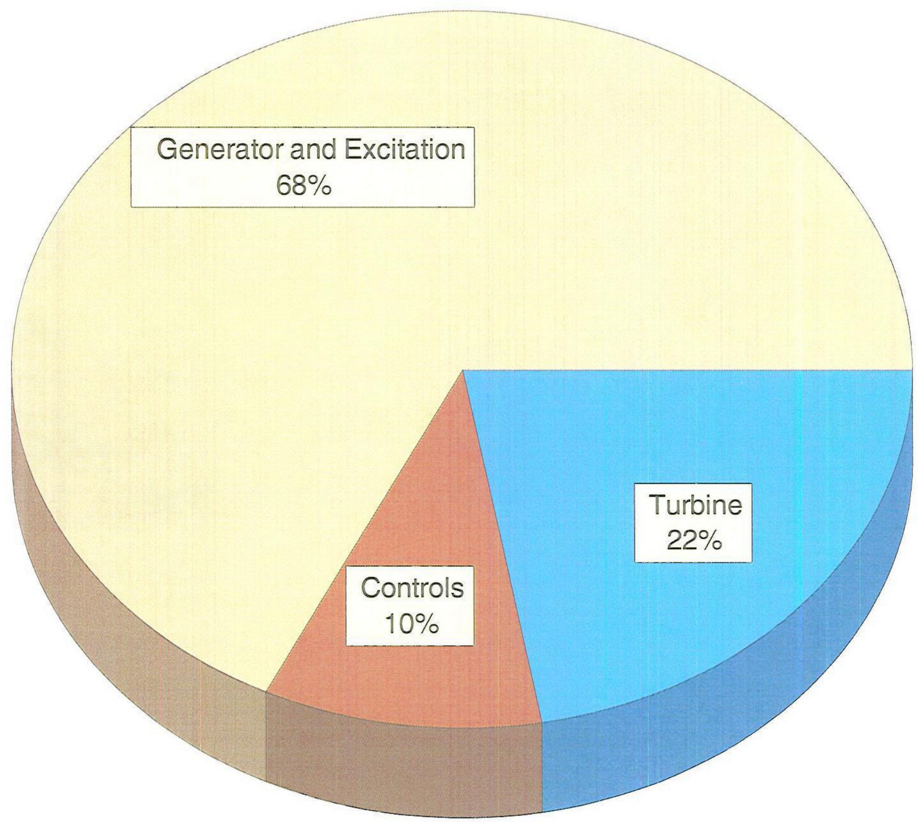
67 (23%) Forced Out

3242 (43%) Lost Hou

24 Suggestions

Turbine - Generator

Percentage of All EA Losses (hours) for T-G S



99 (11%) All Events

50 (17%) Forced Outa

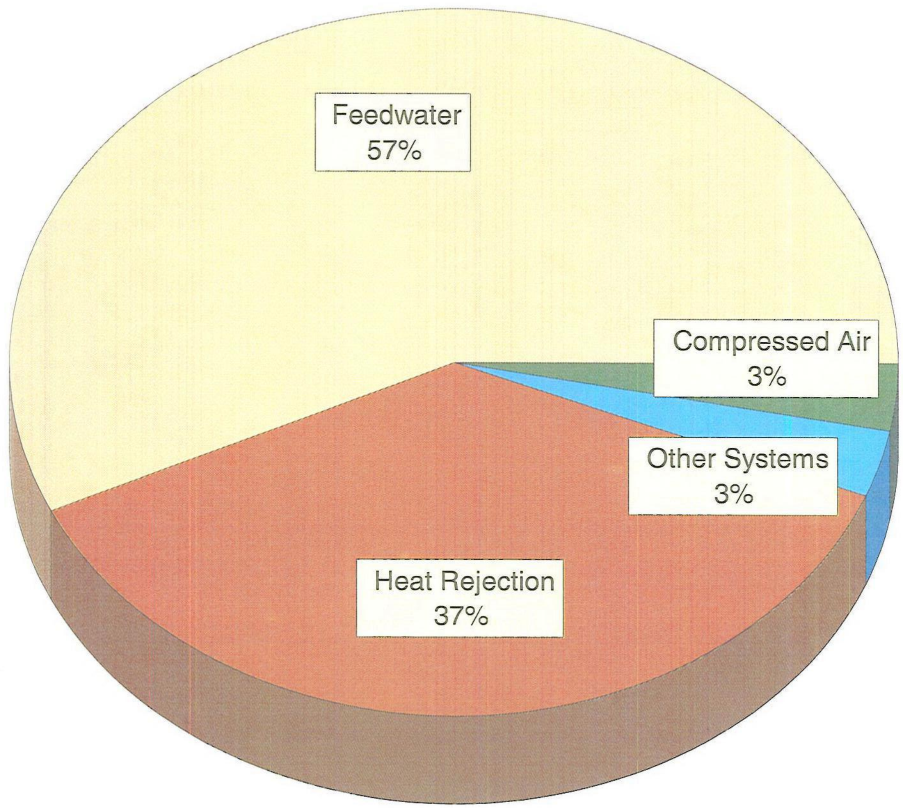
2129 (29%) Lost Hou

1130 (53%) of Lost H
from Field Rewind in

38 Recommendations

Balance of Plant

Percentage of All EA Losses (hours) for BOP S



211 (23%) All Events

57 (19%) Forced Outa

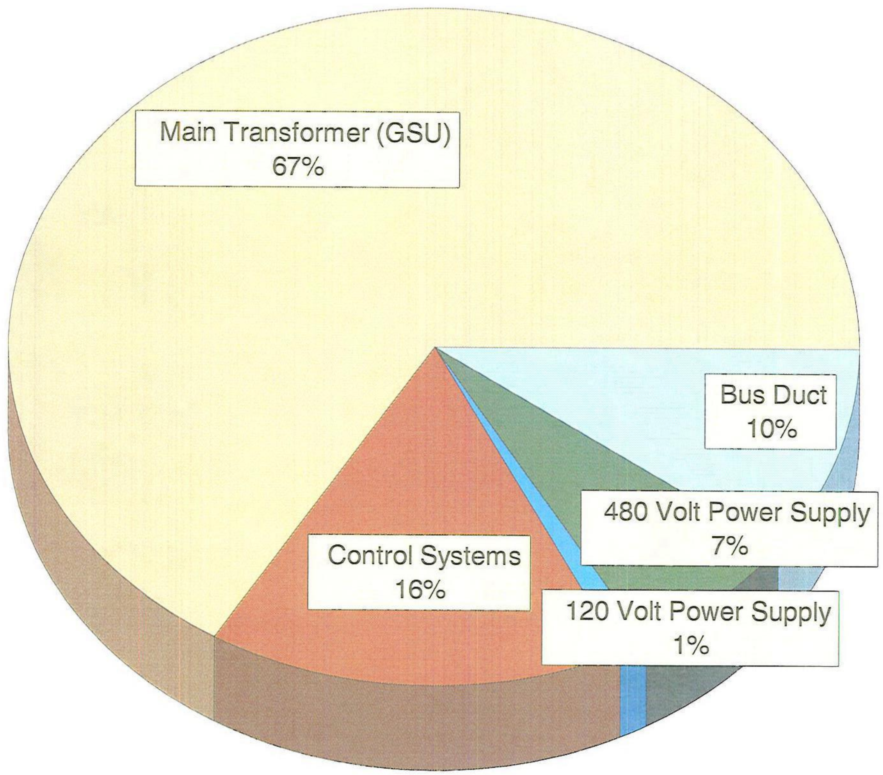
493 (7%) Lost Hours

29 Forced Outages Fr Controls

33 Recommendations

Electrical Systems

Percentage of All EA Losses (hours) for Electri



73 (8%) All Events

39(13%) Forced Outage

559 (8%) Lost Hours

26 Suggestions

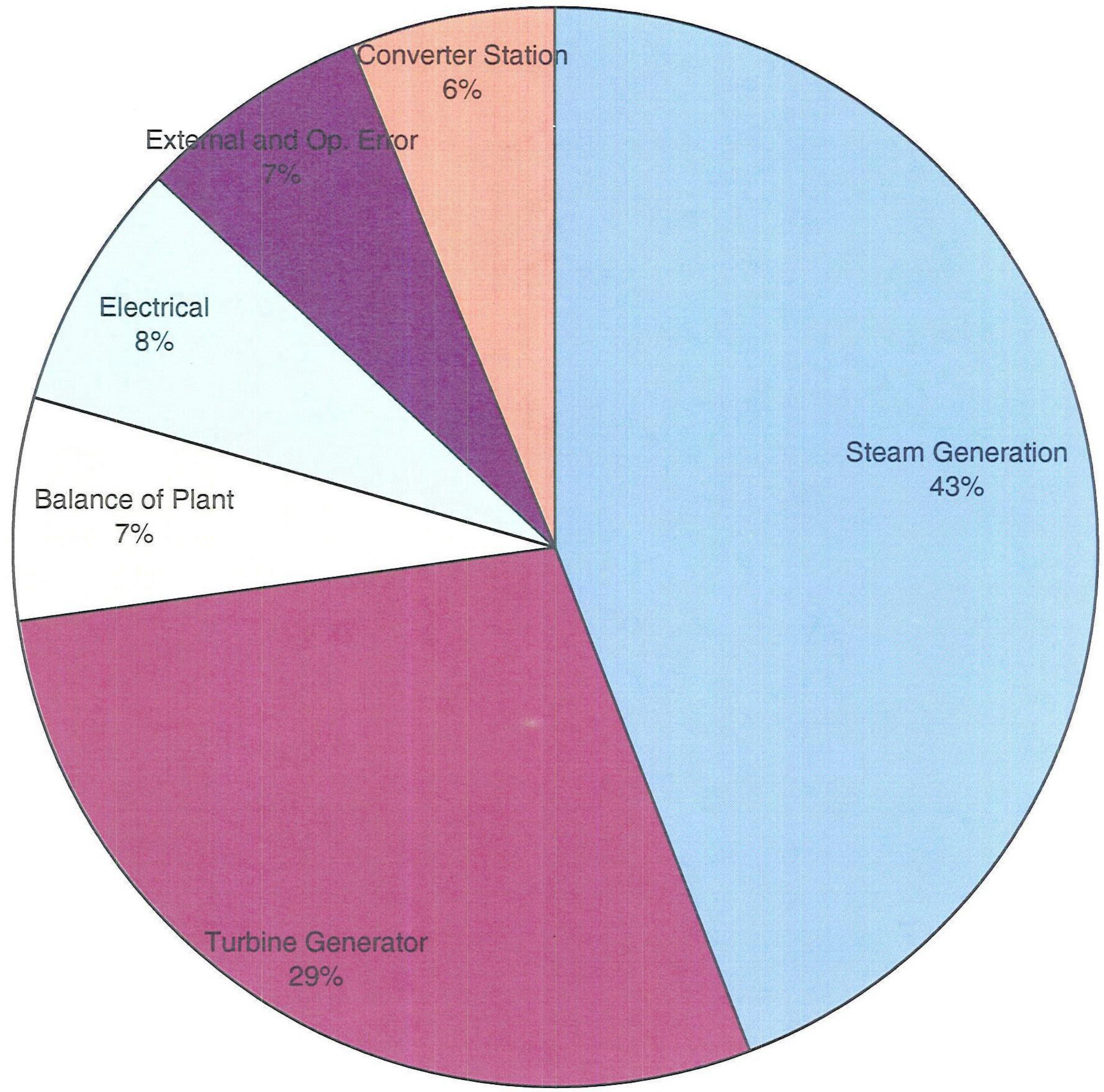
Converter Station

- Critical Systems and Subsystems
  - Systems That If Lost Cause Loss of T
- Focused on Spare Parts
  - 41 Suggestions for Additional Spare P
- Purchasing Additional Spares Can Transmission Availability Losses
  - March 2006 Filter and Reactor Incide

Summary

- Focus Should Be On:
  - Boiler Tube Leak Reduction – #1 Fac
  - Generator Reliability
  - Transformer Reliability
  - Boiler Feed Pump Controls Reliability
  - Converter Station Spare Parts
- 121 Suggestions for Improving Ge Station Availability
- 54 Suggestions for Improving Con Station Availability

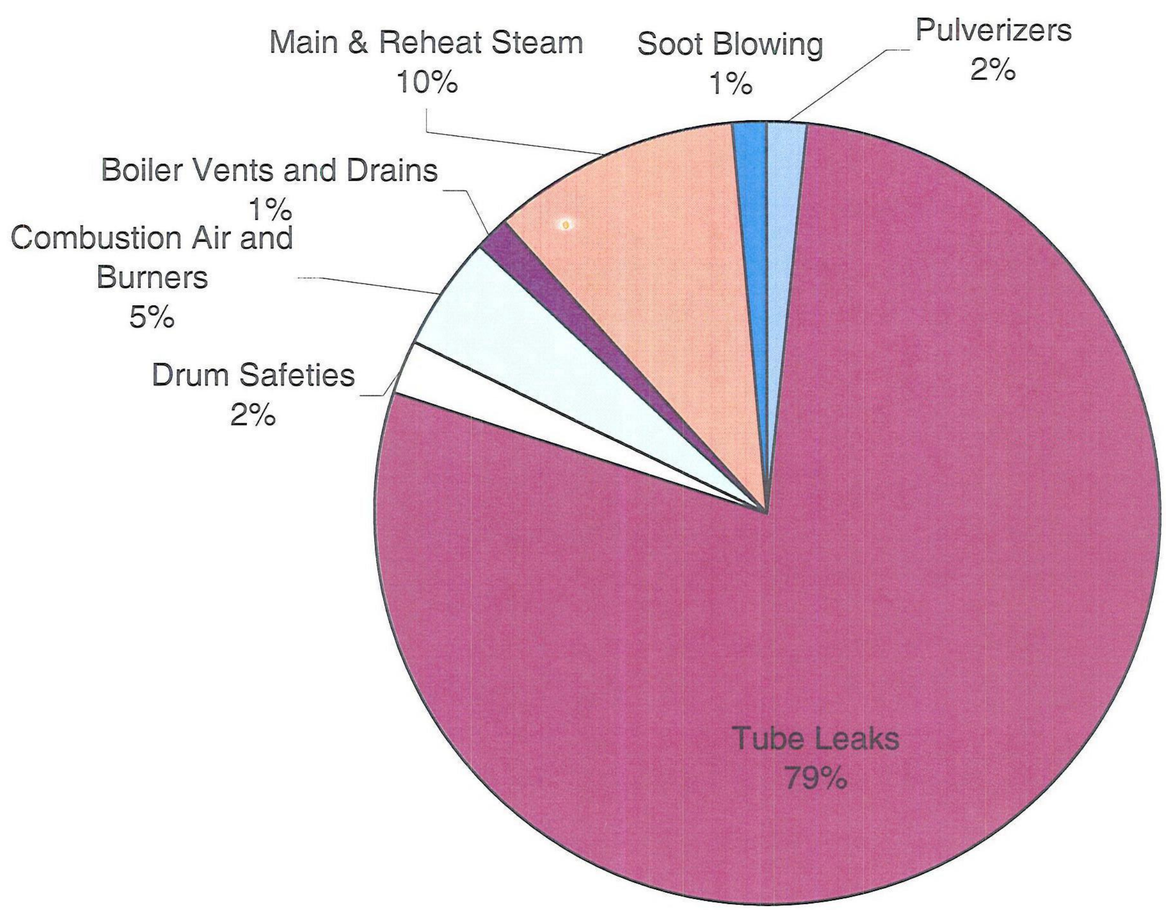
IGS
Loss of Availability by Major System



Includes all generation lost except for Planned Outages and Planned Derates.

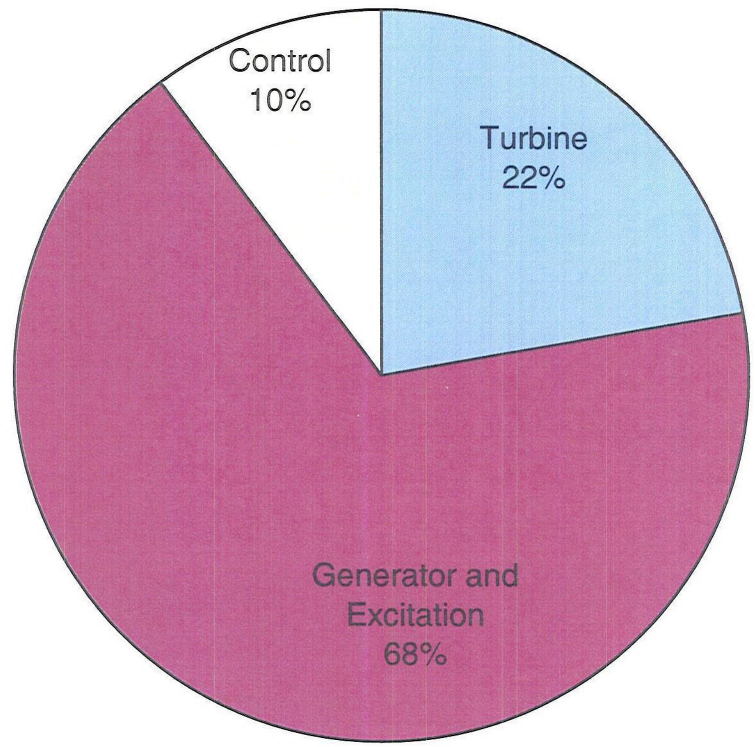
Steam Generator Losses by Subsystem

(Percentage of all Steam Generator Losses of Equivalent Availability)



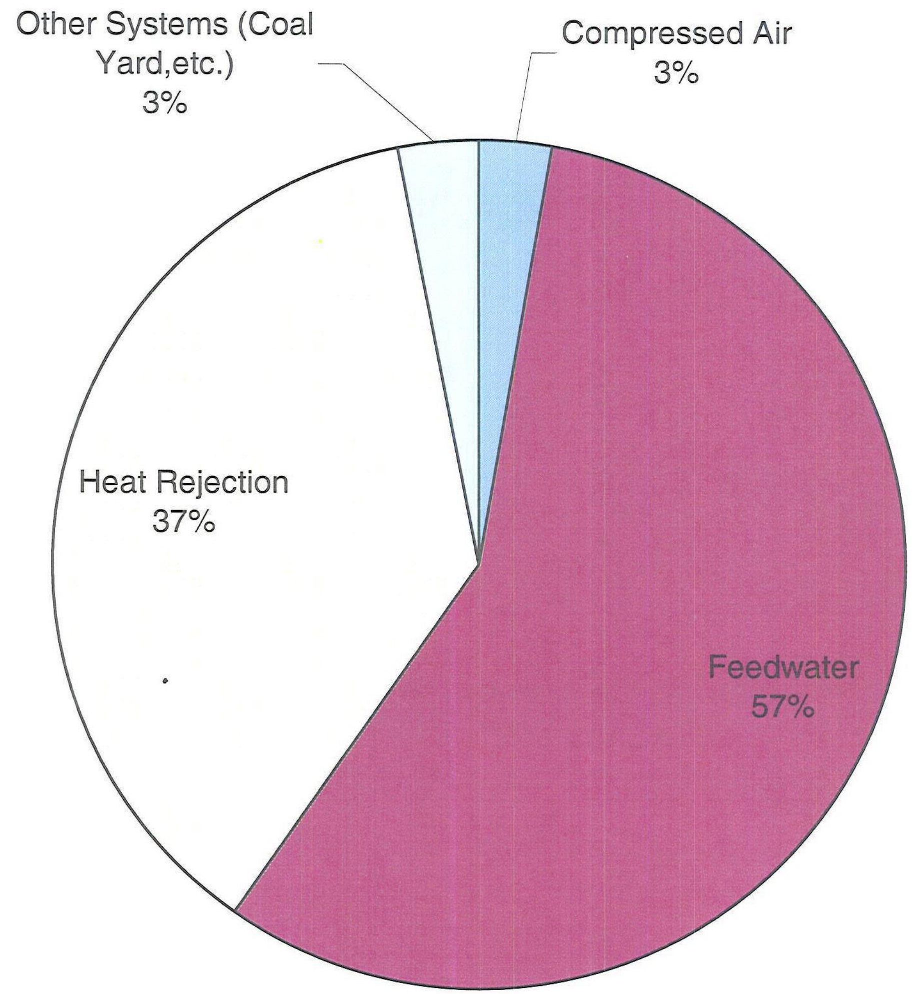
Turbine Generator Losses by Subsystem

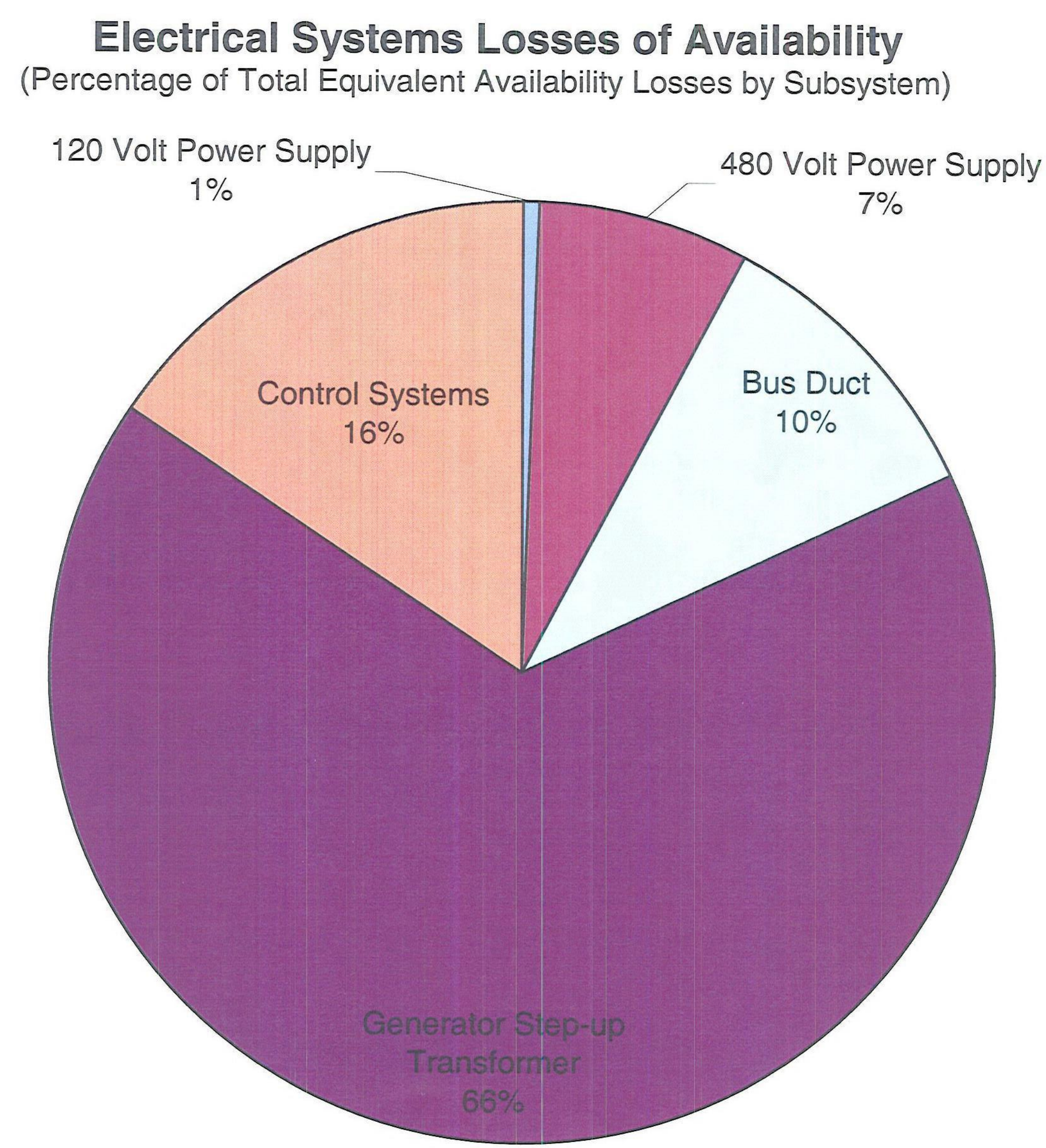
(Percentage of all Turbine-Generator Losses of Equivalent Availability)



Balance of Plant Systems

(Percentage of Total Equivalent Availability Losses by Subsystem)




Electrical Systems Losses of Availability
(Percentage of Total Equivalent Availability Losses by Subsystem)
120 Volt Power Supply
1%
480 Volt Power Supply
7%
Control Systems
16%
Bus Duct
10%
Generator Step-up
Transformer
66%

August 26, 2008

Mr. Nick C. Kezman
Operating Agent for Intermountain Power Project
Los Angeles Department of Water and Power
111 North Hope Street, Room 1263
P.O. Box 51111
Los Angeles, CA 90051-5700

Dear Mr. Kezman:

<u>Status of Greenhouse Gas (GHG) Reduction Study Recommendations</u>

In your letter of June 5, 2008, you requested us to look at four projects for reducing GHG emissions. The status of these four projects is:

1. Cycle Isolation Audit: We will complete the audit during this calendar year and make the valve repairs identified during the next scheduled outages.

2. Variable Frequency Drives for Condensate Pumps: Funds were placed on the 2009-2010 Preliminary Capital Budget. We will continue to evaluate the cost effectiveness of this project for the final budget.

3. Variable Pressure Operation: We do not recommend pursuing variable pressure operation at this time. The frequent small load changes requested by the Energy Control Center (ECC) could cause the boiler controls to go unstable.

4. Replacement of Primary Air (PA) Heater Basket and Seals: The replacement of the Primary Air Heater Baskets is already scheduled for the next two major outages because they have reached the end of their useful life. Black & Veatch (B&V) believed that we could return the PA Fans to low speed by changing out the primary air heater baskets and seals. We do not think that is possible because of the pressure required to maintain flow through the pulverizers. We are exploring other options for returning the PA Fans to low speed.

<u>Cycle Isolation Audit</u>
We budgeted $250,000 in this year's (2008-09) budget to inspect the DMAD pipeline. We actually completed that inspection using funds from last years budget which will allow us to use some of that budget allocation to complete the cycle isolation audit you requested. We anticipate completing the audit on both units before the end of this calendar year so we can repair the leaking valves and other losses during the next available outage. We will send you a copy of the final report along with an estimate of CO_2 reduction we were able to accomplish by implementing the suggestions contained therein.

Variable Frequency Drives for the Condensate Pumps
We have not been able to spend very much time reviewing this project yet. We used B&V's estimate and placed funds on the preliminary 2009-10 budget to complete the work on Unit 2 in 2010 and Unit 1 in 2011. We are currently in the process of getting estimates from several drive suppliers for the necessary equipment. We plan to complete a more detailed analysis of the costs and benefits of this project between now and the submittal of the final budget.

Variable Pressure Operation
We have been utilizing variable pressure operation to reduce heat rate since initial commissioning. Prior to the Alstom High Pressure Turbine Dense Pack Project, the four turbine control valves operated in partial arc admission mode which means the valves opened sequentially. At full load in partial arc, two valves would be full open, a third around 70 percent and the fourth around 30 percent open. This is a very efficient way to operate the control valves as most of the steam flow passes through the valves unimpeded. In variable pressure mode, as load was reduced, the boiler pressure also decreased to maintain the valves as open as possible.

The HP Dense Pack Modification required that the turbine operate in full arc admission, meaning the four control valves operate concurrently. Partial arc admission was disabled as part of the dense pack project because the HP turbine nozzle block could not handle the thermal stresses caused by non-circumferential loading. We were aware that we would lose some efficiency through the valves with full arc admission but, we also knew that the extra efficiency gained from the dense pack was much greater than the valve losses.

Right after the uprate was completed, we adjusted the boiler pressure on both units to try and balance the need for best possible efficiency (turbine valves wide open) with the need to maintain some controllability for load variations. We settled on a pressure of 2375 PSI on Unit 1 and 2350 PSI on Unit 2 which put the control valves at about 40 percent open with the units at full load. This gives us the capability of about a 15 MW to 20 MW load change with just the valves and more important, we can make the changes at a rate of about 5 - 10 MW/Minute.

If we reduce the boiler pressure to the point where the control valves are fully open at full load, the trade off will be the loss of controllability. The Energy Control Center (ECC) currently changes IGS load by 5-10 MW for short intervals (see the attached graph). We can handle these load swings with the turbine control valves at 40 percent because we can use the steam capacity of the boiler as a buffer. If the valves are wide open and we are using variable steam pressure to control load, all load changes will require immediate changes in fuel and air input to the boiler. These frequent load changes could cause the boiler to go unstable and variable pressure operation would slow down the rate at which we can make load changes to only 1 - 2 MW/Minute.

Variable pressure operation might be possible if the ECC would leave us parked at full load except when significant reductions are needed. We believe that the current mode of dispatch from the ECC would result in unacceptable boiler fuel and air swings if we were in variable pressure operation.

It should be noted, that with variable pressure operation, the units will also be more susceptible to load swings caused by sootblowing, equipment trips and changes in pulverizer configuration.

Primary Air Heater Baskets and Seals
B&V's recommendation to replace Primary Air Heater (PAH) baskets and seals in order to achieve low speed on the Primary Air (PA) Fans is based on an estimated cold to hot side leakage in the PAH's of 40 percent. We do not believe that simply replacing the seals will allow the fans to go to low speed. Returning the fans to low speed operation was the basis for the CO_2 reduction in B&V's study

Based on operational experience over varying coal qualities and seasonal conditions, we have found that a minimum PA Fan discharge pressure of 52 INWC is required for reliable and stable unit operation. Without adequate duct pressure, the pulverizers load up which results in sporadic flame destabilizing surges of coal to the burners. The PA Fan curve attached shows a maximum discharge pressure of 50 INWC on low speed.

Other factors to consider with regard to PA duct pressure:

1. Coal Constituents — Future coal supplies are expected to be higher in ash and have lower heat rate, which will dictate an increase in duct pressure to maintain coal throughput in the pulverizers.

2. Coal Pulverizers — On occasion, 6 mill operation is required. This necessitates a higher duct pressure to force coal throughput and maintain load.

It might be possible at times to operate at the lower speed, particularly in the winter months when air density is higher. However; switching fan speeds while the units are operating also introduces instability to the control systems and has a high possibility of resulting in a unit trip.

The high air leakage rate of 40 percent in the air heaters is more a function of the duct pressure than it is the condition of the seals. When we used to operate at duct pressures less than 40 INWC, the leakage rate was 15 to 20 percent. Even with new seals, we do not believe we could get leakage rates much less than 25 percent at our current higher duct pressure.

The current operating point is identified on the attached fan curve. As can be seen, it is just above the low speed curve, which makes high speed operation very inefficient. We are currently evaluating some other possible options for reducing this inefficiency.

Other GHG Reducing Projects
For your information, we have placed two other projects on the preliminary 2009-2010 budget that have the potential to reduce CO_2 emissions.

LP Turbine Advanced Packing and Seals: Overhaul of the LP Turbines is scheduled for 2010 and 2011. As part of the overhaul, the radial packing that prevents steam flow down the shaft between stages and the radial spill strips that prevents steam flow between the blades and the housing are usually replaced. We have placed a project in the preliminary capital budget to replace the packing and spill strips with an advanced design that will reduce steam leakage between turbine stages and improve turbine efficiency. We will complete an evaluation of the heat rate improvement and CO_2 emissions reduction by the time the final budget is submitted. We believe this project can be justified on the heat rate savings alone with no carbon taxes in the economic calculations.

Cooling Tower Mechanical Renovation: B&V recognized the potential for reducing GHG emissions by improving cooling tower performance in their report but, they said it was outside the scope of their project due to the large amount of engineering it would have required to evaluate. The plastic parts in the cooling towers have about reached the end of their useful life and need to be replaced. The combination of sunlight and chlorine slowly embrittles the plastic causing it to crack and break. In preparation for this project, we plan to contract with an engineering firm experienced in retrofitting ceramic towers to improve performance. Funds for the engineering were placed on the 2009-10 budget. We will have a better understanding of the expected performance improvement after the engineering work is completed.

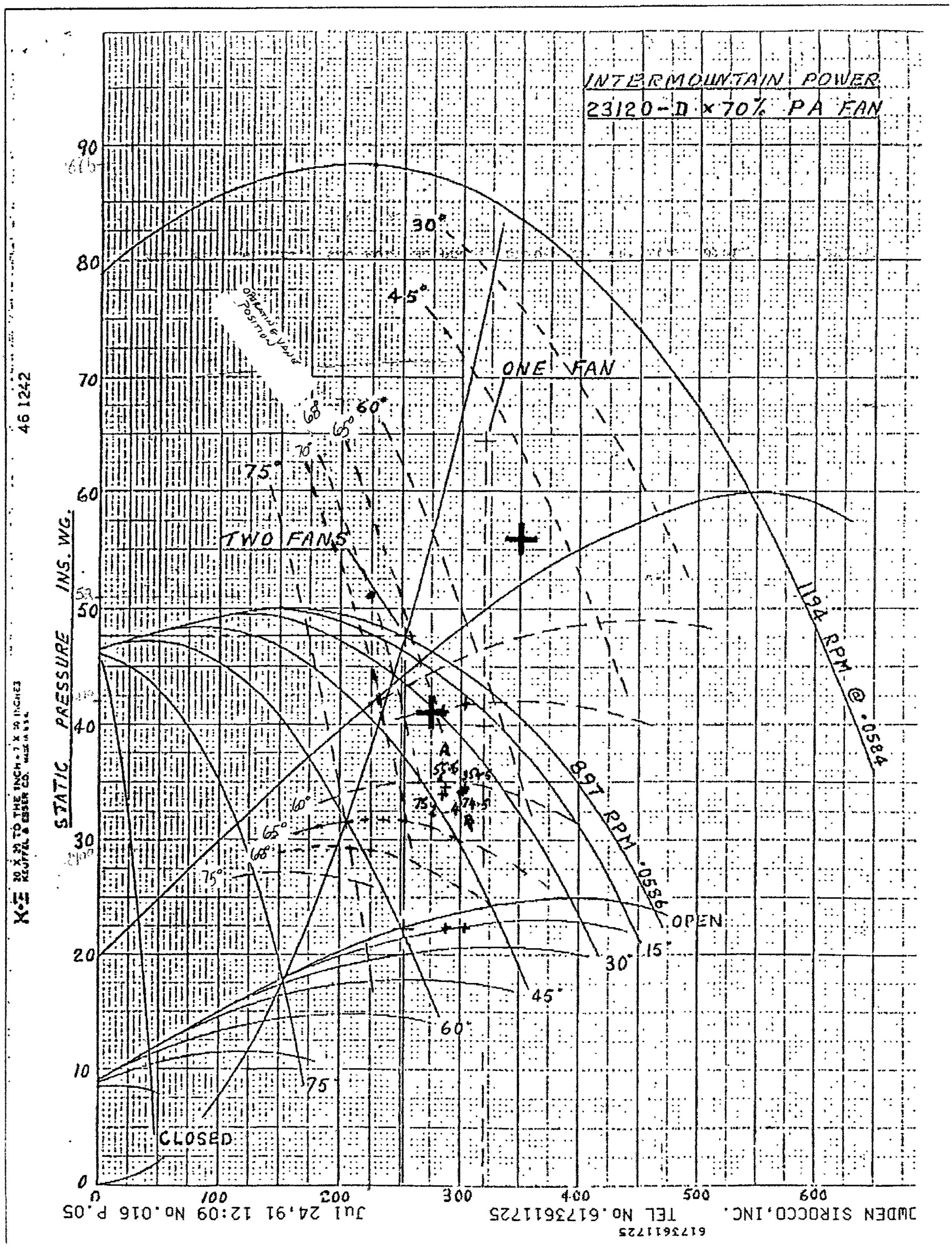
If you have any questions concerning these projects, please contact Jerry Hintze at extension 6460.

Sincerely,

George W. Cross
President and Chief Operations Officer

JKH:jmj

Attachment


INTERMOUNTAIN POWER
23120-D x 70% PA FAN
STATIC PRESSURE INS. WG.
ONE FAN
TWO FANS
1194 RPM @ .0584
897 RPM .0556
OPEN
15°
30°
45°
60°
75
CLOSED
30°
45°
60°
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K&E 20 X 20 TO THE INCH 7 X 10 INCHES KEUFFEL & ESSER CO.
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TEL NO.6173611725
OWDEN SIROCCO,INC.

IP12_000219

Jerry Hintze
Office Hard Files
Studies

Outline of Plan for Reliability Assurance Project

The project will be broken down into five different steps:

1. **System Criticality Assessment**
   a. Objective: Evaluate and identify the plant systems that by design, have the highest potential for negatively affecting availability of IGS and ICS.
   b. Tasks:
      i. Using the original Plant System Codes, review each plant system and sub-system and identify system which impact plant availability.
      ii. Assign a criticality index number to each system and sub-system based on the potential for negatively impacting plant availability considering such things as redundancy of equipment and past history of availability losses from the system.
   c. Result: A spreadsheet of all plant systems and sub-systems ranked by the potential to negatively affect plant availability with documentation of rationale used for ratings. The remaining steps of this project will only be completed for the systems with significant potential to reduce availability. This will focus the efforts to the areas with the highest potential for improvement.

2. **Assessment of Condition Monitoring**
   a. Objective: Evaluate the available methods for monitoring the condition of the systems and equipment both on and off-line.
   b. Tasks:
      i. Review each piece of equipment within the sub-system to determine what methods of condition monitoring are available for that equipment.
      ii. Review what condition monitoring is currently being done and evaluate possible changes to our current programs.
   c. Results: Recommendations for changes to the plant condition monitoring programs. A report by system code of possible condition monitoring, current monitoring programs and rationale for changes to our current program.

3. **Assessment of Maintenance Plans and Methods**
   a. Objective: Evaluate the current and available methods, plans and programs for maintaining the systems, sub-systems and individual pieces of equipment.
   b. Tasks:
      i. Review the current and available maintenance methods, practices and procedures for each system.
      ii. Review possible changes to the maintenance plans, evaluate the changes both technically and economically.
   c. Results: Recommendations for changes to the existing maintenance program for each system. A report by system code of the existing maintenance procedures, available methods and rationale for changes.

4. **Critical Spare Parts Evaluation**
   a. Objective: Evaluate what critical parts are necessary for each system and piece of equipment.
   b. Tasks:
      i. Review what parts are necessary to prevent significant reductions in availability in the event of a failure
      ii. Inventory which of those parts are actually available (physically verify) and identify condition of parts.
      iii. Economically evaluate the possible purchase of additional parts
   c. Results: Recommended list of additional spare parts that should be purchased and a report on the status of spare parts in the warehouse.

5. **Plan for Future Renewals and Replacements**
   a. Objective: Plan for future renewals and replacements by identifying them as far ahead as possible.
   b. Tasks:
      i. Review each system and forecast remaining life of equipment.
      ii. Economically evaluate each possible project and determine an estimated year for completion and project cost.
   c. Results: Recommended list of renewals and replacements including smaller projects not shown on previous 10-year budgets.

Balance of Plant Systems

Introduction and Description of Analyzed Systems

The operation of an efficient coal fired power plant requires careful observation and maintenance of many integrated auxiliary systems. These auxiliary systems will be subjected to changing operating regimes, fuels, and environmental demands during the life of the facility. The maintenance of these auxiliary systems is also often subordinate in importance to the boiler, turbine, and generator.

The intent of this section is to review what auxiliary systems are critical to the availability of the facility and to identify improvements that can be made in both operation and maintenance to insure their long term viability.

For this analysis, Balance-of-Plant (BOP) Systems consists of all critical systems (Criticality 1 or 2) other than the Turbine-Generator, Steam Generator and for this analysis, Electrical Systems. The Converter Station is also not included. Even though the coal yard was not considered critical because of inherent redundancy, a brief review of that equipment was also completed.

Electrical systems would generally be considered a BOP system by most definitions but, concerns over recent problems with electrical systems make it prudent to analyze the electrical equipment as a separate system to give it more attention.

The following System Codes were analyzed with the BOP Systems:

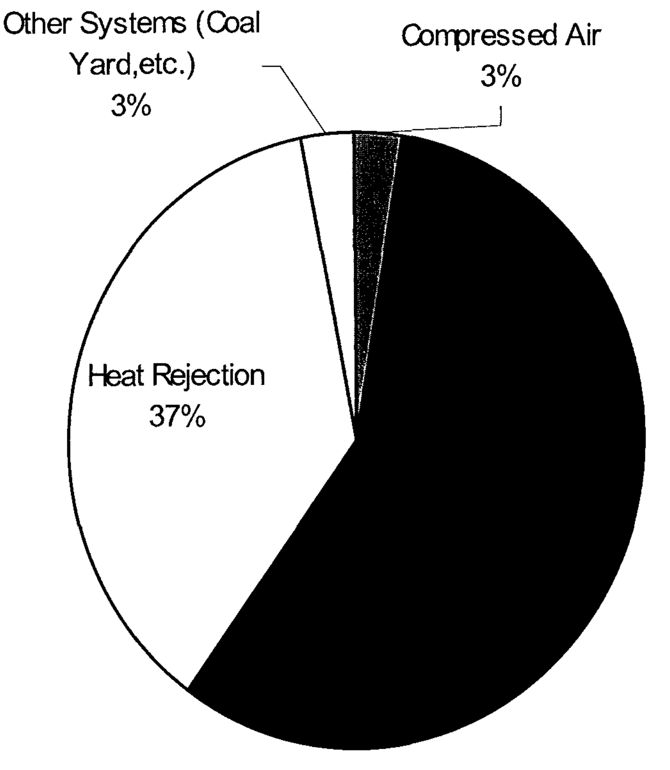
Plant System	System Code
Compressed Air	CAB
Induced Draft	CCE
Equipment Cooling	ECB
Feedwater	FWA
Heat Rejection	HRA, HRC & HRD
All Other Systems	CH, CC, etc.

Losses of Availability

Historically, the BOP Systems have attributed to around 7 percent of the total losses of availability for the station. Combine the BOP statistic of 7 percent with the 8 percent of the electrical systems to get 15 percent and you can compare the IGS experience with data reported by EPRI in a 2002 report[1]. EPRI reported that BOP systems contributed to13.8 percnet of all losses of availability which is very similar to IGS. IGS is also similar to NERC-GADS with the majority of BOP outages being caused by the feedwater system and the heat rejection system.

Balance of Plant Systems

(Percentage of Total Equivalent Availability Losses by Subsystem)



Some of the key statistics gathered from an analysis of the IGS historical data:

	Unit 1	**Unit 2**	**Station**
Number of Events Caused by Balance of Plant Systems	125	86	211
Percentage of All Events Caused by Balance of Plant Systems	25.3%	19.9%	22.8%
Number of Forced Outages Caused by Balance of Plant Systems	35	22	57
Percentage of All Forced Outages Caused by Balance of Plant Systems	22.3%	15.7%	19.2%
Equivalent Hours of Lost Generation Caused by Balance of Plant Systems	243.1	249.9	493
Percentage of All Equivalent Hours of Lost Generation Caused by Balance of Plant Systems	6.6%	6.6%	6.6%

It is interesting to note that while the BOP only causes less than 7 percent of the total lost availability, it does cause more than 20 percent of the total events and almost 20 percent of the forced outages. This means the forced outages from BOP equipment are generally shorter in time but, as frequent or more frequent than the boiler or turbine-generator.

The main culprit on forced outages (unit trips) is the Boiler Feed Pumps (BFP) with 29 forced outages on Unit 1 and 15 on Unit 2 being caused by either the pump or the turbine. The unit trips on drum level excursions caused by the upset. The Boiler Feed Pumps also cause a large number of derates because neither unit can operate at full load with one or the other feed pump out-of-service.

The mechanical aspects of the boiler feed pumps and turbines have actually been very reliable with only a few incidents caused by mechanical failure. Most of the trips or incidents with the boiler feed pumps are associated with the controls or monitoring systems. Correcting the problems with the Boiler Feed Pump and Boiler Feed Pump Turbines (BFPT) would reduce the majority of generation losses and trips associated with Balance of Plant equipment and could significantly reduce the total number of plant forced outages.

Predictive Maintenance

Since the BOP systems incorporate such a large variety of equipment, it is difficult to discuss what predictive maintenance we are currently performing in this area without a general presentation on all available predictive maintenance technologies. Suffice it to say that we utilize vibration monitoring, lube oil condition monitoring, performance monitoring, and any other available technique to monitor and track the condition of this equipment.

The task force meetings came up with the following recommendations for improvements in the predictive maintenance of this equipment:

Testing of Critical Auxiliary Heat Exchangers

The Closed Cycle Cooling Water System provides cooling to many critical pieces of equipment such as Air Compressors, EHC, Stator Cooling, BFPT Lube Oil, FD Fan Lube Oil and ID Fan Lube Oil. We have done little, if any, condition monitoring for these heat exchangers since they were originally placed into service. The failure of one of these heat exchangers could release large amounts of water into critical systems causing extensive damage and downtime.

Even though the Closed Cycle Cooling Water is treated to reduce corrosion potential and the heat exchangers were designed with corrosion resistant materials, we recommend that a program be developed to systematically test these heat exchangers to insure there is no corrosion or erosion occurring.

Compressed Air Usage Audit

Over the 20 years of operation, we have steadily been losing redundancy in the compressed air system because of increased demand. Much of that demand is the result of leakage or inefficient use of compressed air (air horns instead of fans). We recommend that a compressed air usage audit be performed to identify and quantify the locations of air usage and waste and then a program be developed to reduce usage down to insure redundancy is maintained.

Maintenance Improvements

Maintenance of the BOP systems is a combination of Predictive (condition based), Preventive (time based), and Corrected (as-needed) Maintenance. The type used for each piece of equipment is dependent on the value, criticality, and accessability of the equipment or system. The task force recommends the following to improve the maintenance of the BOP Systems:

PM for Air Compressor Back-up Nitrogen Control Air System

The compressors require control air for start-up and operation. A back-up nitrogen bottle system was installed with original construction to provide start-up control air in the event of a black-trip or loss of all control air. This system has not been periodically tested or maintained, because it has never been needed. We recommend that a PM Work Order be established that will periodically trigger the technicians to test and maintain this equipment in the event it is ever needed.

Air Compressor Control Drawings

The control drawings for the air compressors do not reflect all of the changes that have been implemented to the system over the last 20 years. The drawings should be reviewed and updated as needed to make sure the technicians have the information they need to troubleshoot and repair this critical equipment.

Recommended Capital Improvements

The projects below represent some of the major recommendations from the task force meetings. See the list of recommendations for the full list.

Boiler Feed Pump Controls Upgrade

It is easy to see that the main improvement that would increase the reliability of the BOP systems would be to improve the BFP and BFPT controls. We are currently implementing a capital project to upgrade the existing 20 year old GE-MDT20 analog controls with digital controls and a state-of-the-art governor system.

Failures of the BFPT components (seals, labyrinths, blades, rotor, etc.) are typically resultant of actual over-speed conditions and lube oil failure. According to the OEM, the new system will feature a significantly more reliable (99.999 percent reliability) electronic over-speed trip device and redundant lube oil pressure supervisory system. Additionally, both of these systems are on-line testable without having the need to trip the turbine.

Currently, the OEM requires the existing over-speed "governor" to be tested prior to any start-up. This process requires the machine to run up to 10 percent over-speed to be able to calibrate and/or verify the over-speed trip set point. This practice is time consuming and creates additional stress on the components and auxiliaries. The new digital over-speed trip device is reliable, consistent and is not subjected to mechanical wear. It allows online testing without the machine actual over-speed.

We have contracted with GE for the new digital systems. Unit 1 will be completed in April, 2007 and Unit 2 in April, 2008.

Upgrade BFP Recirculation Valve Controls

The controls for the BFP recirculation valves are independent of the pump and turbine controls. We have had four previous forced outages on both units from the recirculation valves coming open. When the recirculation valves open it disrupts the flow of feedwater to the drum and the unit trips on low drum level. The recirculation valves are meant to only operate during start-ups or in the event of a unit trip or upset.

We recommend replacement of the original pneumatic controls for these valve with more reliable digital controls. The digital controls should improve the reliability and response.

Restore Structural Integrity of Circulating Water Make-up Supply Line

We know from previous experience that the 30-inch Prestressed Concrete Cylinder Pipe (PCCP) that supplies make-up water from Water Treatment to the Cooling Towers is probably failing from external corrosion of the reinforcing wires. We recommend that a project be implement in the near future to either repair or replace this line.

Split Air Compressor Control Power

The air compressor control power is currently split so that the loss of one power source will only trip, at the most, two of the three operating air compressors. However; both units cannot operate with only one air compressor, even if the service air is isolated from the control air. We recommend that the control power be split one more level such that only one air compressor will trip with the loss of individual power source.

Split ID Fan Exciter Power Supply

The ID Fan Exciter Power Supply is currently set-up so that it is split between individual cubicles at the Motor Control Center (MCC) level but, that MCC is fed from one Secondary Unit Substation (SUS). This means that the loss of that one SUS will cause all four ID fans to trip, and also the unit to trip. We recommend that the power supply be split so that the loss of one SUS will only result in the loss of two ID fans. This would save a unit trip and only result in a derate until the other two fans could be restored.

Additional Spare Parts

The spare parts below represent some of the major recommendations from the task force meetings. See the list of recommendations for the full list.

Spare Air Compressor Coupling

We currently have a spare air compressor motor, but no spare motor to compressor coupling. We recommend investigating the cost and economic benefit of purchasing a spare coupling to have available in the event of a coupling failure.

Closed Cycle Cooling Water Pump

The Closed Cycle Cooling Water Pumps have been rebuilt several times and some the tolerances and fits are becoming difficult to maintain. We recommend an analysis of the possible purchase of a spare Closed Cycle Cooling Water Pump. Having a spare pump will allow the rebuilds to take place in the shop and will allow more time for restoration and inspection. The spare will also provide a "Ready Spare" in the event of a failure.

Boiler Feed Pump Turbine Couplings

We do not maintain a spare turbine to pump coupling even though we have a spare pump volute. A catastrophic failure could result in significant downtime waiting for the coupling even though the volute is ready to be installed. An analysis should be completed of the possible purchase of a spare coupling.

Spare ID Fan Transformers

The uprate to 950 MWG requires that all four ID fans be available for full load operation. This means that the loss of an ID Fan will result in a derate. Several of the transformers for the ID fan drives have failed previously and the lead time for a replacement is six months or more. We recommend that a review be done of the risk and benefits of purchasing a spare transformer.

Spare Magnetic Coupling for Conveyors 18A and 18B

We have spare motors, gearboxes and pulleys for most coal conveyors. Since we have changed to magnetic couplings in some applications, we have not maintained spares like we previously had with the fluid couplings. Even though the unit could continue to operate with only one conveyor path, the delivery of a new magnetic coupling would take over three months. We recommend purchasing a spare to insure that the coal supply to the unit will not be jeopardized.

Electrical Systems

Introduction and Description of Analyzed Systems

The continued safe and efficient operation of IGS facilities requires careful inspection and maintenance of numerous electrical systems at various voltage service levels. These systems operate in the background for the most part but are as essential to plant availability as the critical equipment served by these systems.

The intent of this section is to review critical electrical systems of the facility and to identify improvements that can be made to ensure their long term viability. Areas addressed and committee recommendations made are detailed in the pages that follow. The analysis in this section was only for electrical subsystems determined to be Criticality 1 or 2. The Converter Station electrical systems will be included in the Converter Station report.

Electrical systems would generally be considered BOP systems by most definitions but, concerns over recent problems with electrical systems make it prudent to analyze the electrical equipment as separate systems to ensure they are given proper attention.

The following System Codes were analyzed with the Electrical Systems:

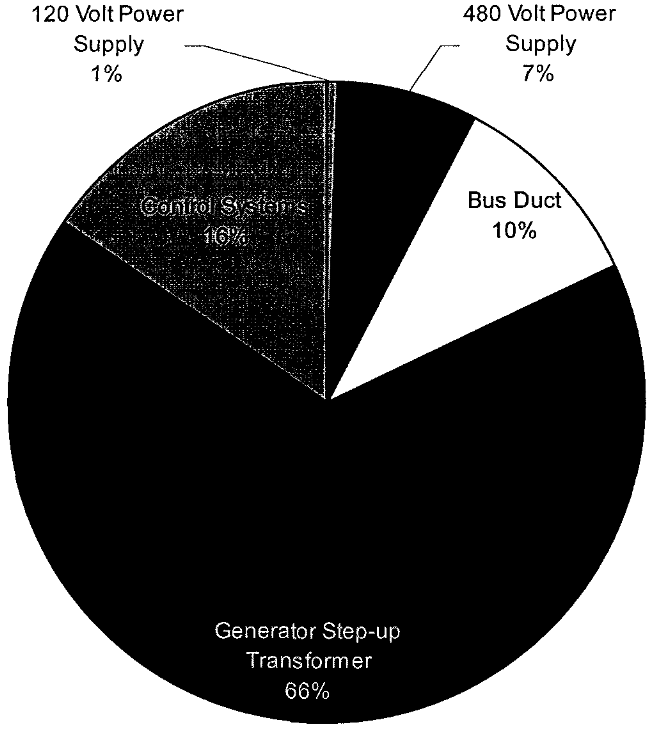
Auxiliary Power System (AP)	**Subsystem Code**
AC Power Supply (120v)	APA
AC Power Supply (480v)	APC
AC Power Supply (6900v)	APE
DC Power Supply	APH
Essential Service AC	API
Essential Service DC	APJ

Control System (CO)	**Subsystem Code**
Coordinated Control (DCS)	COA
Unit Protection	COC
Control & Multi-System Panels	COF

Generator Transformer System (GT)	**Subsystem Code**
Generator Bus Dust	GTA
Generator Transformer	GTB

Electrical Systems Losses of Availability

(Percentage of Total Equivalent Availability Losses by Subsystem)



Losses of Availability

Historically, the Electrical Systems have attributed to just under 8 percent of the total losses of availability for the station. Combine the BOP statistic of 7 percent with the 8 percent of the Electrical Systems to get 15 percent and you can compare the IGS experience with data reported in the EPRI report of 2002 . EPRI reported that BOP systems (including electrical systems) contributed to13.8 percent of all losses of availability which is very similar to IGS experience.

Statistics for Electrical Systems gathered from an analysis of the IGS historical data:

	Unit 1	Unit 2	Station
Number of Events Caused by the Electrical Systems	34	39	73
Percentage of All Events Caused by the Electrical Systems	6.9%	9.0%	7.9%
Number of Forced Outages Caused by the Electrical Systems	20	19	39
Percentage of All Forced Outages Caused by the Electrical Systems	12.7%	13.6%	13.1%
Equivalent Hours of Lost Generation Caused by the Electrical Systems	271.9	287.45	559.33
Percentage of All Equivalent Hours of Lost Generation Caused by the Electrical Systems	7.4%	7.6%	7.6%

Recommended Capital, Predictive, or Maintenance Improvements

Please refer to the complete list of recommendations for the Electrical Systems which are listed on a separate report. The following are the most significant items the task force committee felt were of greatest value to ensure continued high availability of the station. They are listed in order of the primary system and not in order of importance.

Purchase and install transformer oil continuous dissolved gas analysis equipment on the Aux Transformer 1A, Aux Transformer 1B, and the Generator Step-up (GSU) Transformer in both units.

We currently sample the oil every six months and have it tested by Doble. Recent catastrophic events in the United States suggest the need for continuous monitoring. Several of the events occurred in a short time frame. Testing only at six month intervals may not uncover problems that could develop shortly after a test and escalate to destruction in just a few days or weeks without any indication. Estimated time to replace an Aux Transformer is six days. Estimated time to replace the GSU is two weeks.

Purchase and install a wet cell battery continuous monitoring system for the Essential AC and Unit Battery DC station batteries.

Currently the preventative maintenance consists of taking cell voltage and specific gravity readings quarterly along with visual inspections and load testing during outages when directed by Engineering. New technology has been developed to more thoroughly monitor wet cell battery systems. The system automatically monitors a plurality of parameters on all cells in a lead-acid storage battery system and alarms if any parameter of any cell exceeds specified limits.

Increase use of thermography technology to include scanning online of Generator Breaker, Switchgear, and other equipment.

Add viewing windows to switchgear lineups, iso-phase housings, and various loads to allow thermography scan with equipment in the operating condition. Windows of special material can be installed which retain the enclosure integrity yet allow infrared cameras to "see" through it.

Purchase and install replacement Essential AC Inverters in Unit 1.

Unit 1 inverter transformers are older than those in Unit 2. The equipment is obsolete and nearing the end of its useful life. Inverters removed from Unit 1 could be stored and used for spare parts to keep Unit 2 equipment in service. This was recently done in a similar manner to the Unit and Essential Battery Chargers.

Replace ABB Generator Breaker at the first opportunity. Order lead time is approximately 2 years.

Our generation of the ABB breaker was obsoleted in 1999. Parts availability is rapidly decreasing. When parts are available, they come at an extremely high price with long delivery. This project is currently planned for 2011 and 2012. This needs to be moved up because equipment is no longer supported. The breaker was manufactured in Switzerland.

Purchase and install infrared detection monitoring system on the Iso-phase Bus Duct.

This newer technology is specifically designed for uprated generators where bus work has not been upgraded. Information is available remotely. The information can be used to evaluate unbalance between phases. It can detect heat build-up generated from loose arcing connections. We have had a bus duct failure at IGS resulting in a forced outage of several days. This technology will allow us to know beforehand when a problem area is developing and can be resolved during normal planned outages.

Purchase and install new digital temperature monitoring system for Units 1 and 2 GSU Transformers.

The current Qualitrol system originally provided is obsolete. Current equipment does not have the accuracy of the new digital system. Maintenance calibration costs are higher. With the unit uprates to 950MW, the GSU runs near its thermal limit in the summer time. Close monitoring is essential.

Fully dress and test the spare GSU and Aux Transformers. Install bushings, bushing pockets, and CTs.

These two transformers are critical spares in the event of a catastrophic unexpected loss. The transformers were shipped unassembled and have been stored that way. The loose parts have been put in the Warehouse and used to service the installed equipment. In the worst case scenario of a catastrophic failure and fire, it is likely that nothing could be salvaged. Fully dressing the spares would make sure that all parts for a complete installation are on site. With bushings installed, it would further allow proper testing of the transformer periodically to ensure that the transformers are truly in a serviceable condition.

This would also require the purchase of replacement spare bushings and other loose materials for warehouse stock for maintenance of the existing equipment. If our only spare bushings, for example, are installed on the spare transformers, they would not be available for use during outages and other times when parts are changed on the transformer.

Electrical System Spare Parts Analysis

Please refer to the complete list of recommended spare part recommendations for the Electrical Systems which are listed on a separate report. The following are the most significant items the task force committee felt were of greatest value to ensure continued high availability of the station. They are listed in order of the primary system and not in order of importance.

Prove viability of capital spare printed circuit boards already in the Warehouse.

We have found brand new capital spares in the Warehouse that will not operate when installed in the equipment. UPS cabinets in system APA have been a problem and other systems could have the same potential. Often there is only a single board in stock and must be known to be good. Develop a plan to exchange warehouse spares with installed boards during outage windows.

Purchase one complete spare switchboard for a PC Distribution Panelboard, Essential AC Distribution Panelboard, and a DC Unit Battery Distribution Panelboard.

These panelboards are fusible disconnect style manufactured by ITE and are each a different size. They are obsolete and no longer supported. A fault on the bus could destroy an entire panelboard. We only stock a very few individual fusible units. Loss of any of these system panelboards would cause loss of selected critical equipment.

Purchase spare tray cable of common types to make emergency repairs.

Fires and other sources of damage could be devastating in the critical generation areas where cable is exposed in cable trays. We need to stock common power, instrument, and control cable types along with a selection of high voltage cable. Cable is not as readily stocked in vendor inventories as it once was. We have tight cable specifications at IGS, requiring flame retardant jacketing and other features, which makes cable suitable for us less main stream.

Purchase complete bus duct assemblies for SUS xA11 and xB11 for both units.

Failure of this bus duct has already caused a Cooling Tower reduction in the number of fans available for service for a period of three months. Fortunately, it was in the winter of 2005-2006 and did not cause a loss of generation, but could cause a derate if this failure were to occur in the summer months.

Purchase spare Cooling Tower SUS Transformer.

A single Cooling Tower SUS is not capable of running all 24 Cooling Tower Fans when there is only one SUS in service and the tie breaker closed. If an outdoor transformer were to fail, we would be in a derate situation for several weeks while a replacement transformer was procured. This purchase is in the current Capital Budget.

Purchase spare Iso-Phase Bus Duct jumper section complete with braids and shunts.

If a catastrophic event occurred at one of the breaker poles, we would need a way to continue to operate while replacements parts were ordered. We have some spare parts to a breaker pole but not a complete pole with the housings. An iso-phase bus duct section would be inserted where the Generator Breaker pole was removed. The spare section would include braids and shunts for a complete connection end-to-end to existing iso-phase bus on either side of the Generator Breaker. Syncing of the generator along with protection would be relocated to ICS control.

Purchase a spare GSU neutral grounding resistor assembly.

There is no blast wall between the GSU transformer and the grounding resistor. In the case of a catastrophic explosion of the GSU, damage to this adjacent structure would most likely render the equipment inoperable. We have a spare GSU but not the related grounding resistor assembly.

Executive Summary

Introduction

Until new generation technologies become available, coal-fired generation will play the major role in supplying the energy for this country. Fossil-steam plants generate more than 70 percent of all electric energy and the plants average more than 30 years old. It is imperative that we take any measure available to maintain the reliability and efficiency for which this facility is well known and upon which its economic future depends.

It has always been our objective to maintain the plant in "As-New" condition. Nevertheless, organizations can become entrenched in their modes of doing things and IPSC is not immune to this form of unintentional complacency.

The hope is to rekindle innovation and imagination among the experienced personnel of this plant upon whom we so much depend, but also upon whom may be becoming myopic by the long years of service.

Objectives

- Identify the plant systems that have the highest potential for negatively affecting availability.
- Evaluate the available methods for condition monitoring.
- Review current maintenance techniques and philosophies.
- Insure that all necessary critical parts are available when needed.
- Plan for future renewals and replacements.

Approach

- Review past operating history to determine which plant systems have caused reductions in availability.
- Hold Availability Improvement Meetings with key plant personnel to discuss the causes of availability losses and ways to improve availability.
- Perform detailed analysis of the suggestions received, including estimated cost and economic benefits.
- Track all suggestions and report status to staff in insure full resolution, management, and owner buy-in.
- Create Availability Improvement Working Groups to continue the improvement process.

Only the first two approach activities are complete at this time and this report covers the results of those efforts.

Availability Improvement Project

Introduction and Purpose of Project

Until new and innovative power generation technologies become available, coal-fired generation will continue to play a major role in supplying the energy needs of this country. All told, fossil-steam plants generate more than 70 percent of all electric energy in the country and these aging plants, on average more than 30 years old, will remain the foundation of the power industry for the immediate future.

While the Intermountain Generating Station is still one of the newest and most modern large coal-fired generating stations in the country, it is now exceeding 20 years in service and some of the components and equipment are starting to show signs of that age. With no foreseeable end to the need for the power from this station, it is imperative that we take any prudent measure available to maintain the reliability and efficiency for which this facility is well known and upon which its economic future depends.

With that imperative in mind, this project was developed - Availability Improvement Project. The project has five objectives:

1. **System Criticality Assessment:** Evaluate and identify the plant systems that, by design, have the highest potential for negatively affecting availability of IGS, ICS and STS.

2. **Assessment of Condition Monitoring:** Evaluate the available methods for monitoring the condition of the systems and equipment both on and off-line.

3. **Assessment of Maintenance Plans and Methods:** Evaluate the current and available methods, plans, and programs for maintaining the systems, subsystems, and individual pieces of equipment.

4. **Critical Spare Parts Evaluation:** Evaluate what critical parts are necessary for each system and piece of equipment.

5. **Plan for Future Renewals and Replacements:** Plan for future renewals and replacements by identifying them as far ahead as possible.

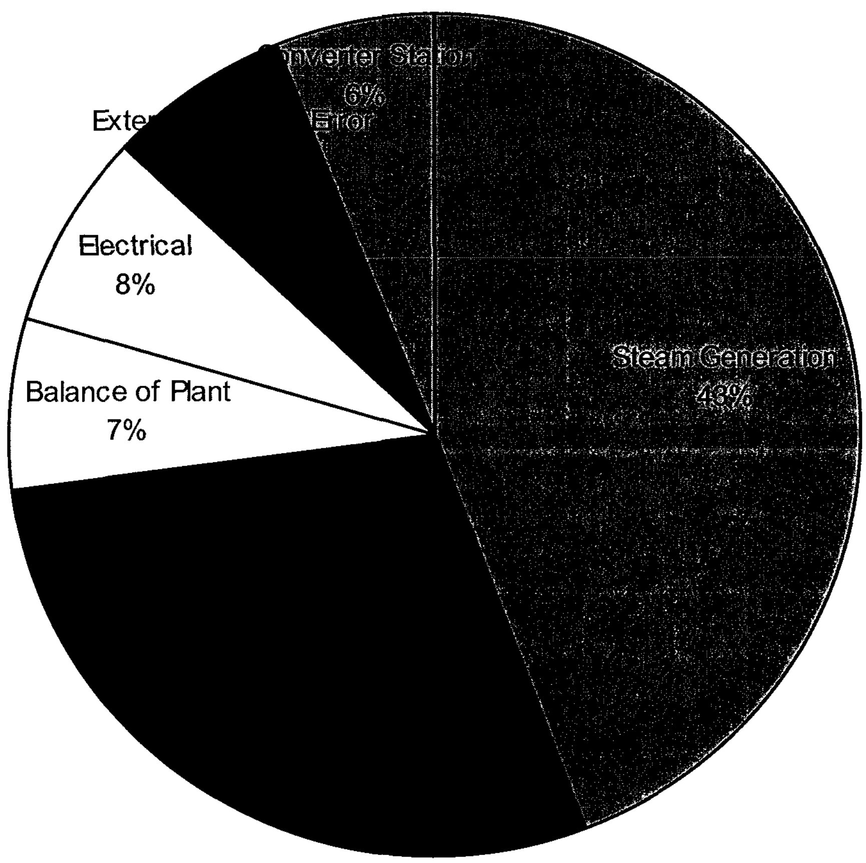
None of these objectives in and of themselves are new or different from what we have been trying to accomplish at IGS since the plant went on-line. In fact, it has always been our objective to maintain the plant in "As-New" condition and much effort has been expended toward that means over the years. Nevertheless, organizations can become entrenched in their modes of doing things and IPSC is not immune to this form of unintentional complacency.

The hope for this project is to rekindle innovation and imagination among the experienced personnel of this plant upon whom we so much depend but, also upon whom may be becoming myopic in their viewpoint by the long years of service.

Historical Losses of Availability

The first step in this process was to look at the historical losses of availability for the station to determine which pieces of equipment or systems have caused the highest number of forced outages or derates over the approximate 20 years of service. The graph below shows the losses by major pieces of equipment.

IGS
Loss of Availability by Major System

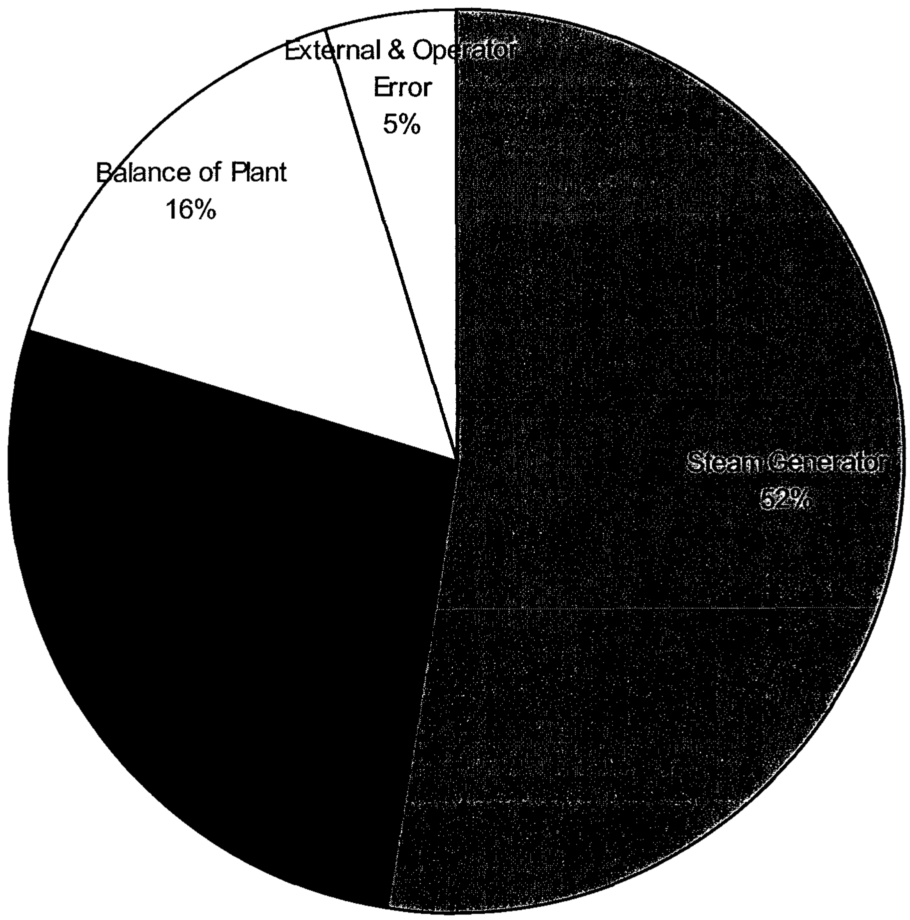


Includes all generation lost except for Planned Outages and Planned Derates.

As would be expected, the boiler or steam generator has historically had the largest impact on availability followed by the Turbine-Generator. Clearly, boiler reliability is the deciding factor in the economic viability of this facility and is the major factor in ensuring high capacity factors.

NERC-GADS Fossil Steam Plant Data

(1995-1999, All Unit Sizes, All Fuels, Average size approx. 300 MW)



In a 2002 publication (*Productivity Improvement Handbook for Fossil Steam Power Plant: Third Edition, 1006315),* EPRI published some availability numbers for all fossil fuel plants across the country. The results are published below. As you can see, these numbers compare very similarly with the experiences at IGS. EPRI did not break out electrical systems from the balance of the plant so no direct comparisons could be made in that area.

Rationale for Critical Systems

In order to focus this project on the systems most affecting reliability, the different plant systems and subsystems were categorized by overall impact on plant availability. The goal was to assign a Criticality Factor (CF) for each plant system or subsystem. This system was similar to one used by LADWP right after initial construction to review the spare parts and maintenance needs for the plant. The categories used were as follows:

CF 1 = Equipment failure causes 100 percent load loss immediately. No Redundancy.

CF 2 = Equipment failure causes partial load loss immediately. Redundancy not capable of 100 percent output.

CF 3 = Equipment failure causes no load loss. Redundancy capable of 100 percent output.

CF 4 = Equipment failure causes only inconvenience. All other process equipment not directly tied to production.

For this project, only CF 1 and CF 2 systems will receive a detailed analysis. Some analysis was also done of the coal yard even though it was deemed to have been CF 3 because of redundancy. This does not mean that the other plant systems are not important or necessary, we are just trying to focus this detailed review and analysis on those pieces of equipment that have or are most likely to cause losses of generation.

The factors used for determining the appropriate CF were, historical events, design redundancy, part availability, repair time, accessibility, and experience-based intuition.

The list of systems assigned CF 1 or CF 2 are attached at the end of this section. The list of all systems can be found in the appendix.

Project Implementation

This report will be just a bunch of words without a plan and the follow-up to make something positive happen. Lofty objectives like these cannot be achieved by any one department or group, it has to be done as a team effort with the support of management and the project owners. The value of the efforts will only be realized if improvements in availability can be achieved and maintained over long periods of time.

The actual implementation of this project will be in five steps:

1. Complete a critical systems assessment to determine which plant systems and equipment should be analyzed. This has been completed.

2. Hold availability improvement meetings with key plant personnel for each of the five areas outlined in this report. The purpose of the meetings will be to identify possible changes to the predictive maintenance programs, maintenance schedules, spare parts needs, and to suggest possible future capital improvements. This has also been completed.

3. Perform detailed analysis of the suggestions received from the availability improvement meetings. The analysis should include estimates of the cost of implementation and economic benefits and should rank the suggestions on the potential impact to availability. Management and owner support should be obtained for those projects that will be taken to full completion.

4. The list of approved recommendations should be tracked with regular status updates. Schedules should be developed for each recommendation. Where needed, the recommendations should be budgeted on either the capital or O&M budget.

5. Create Availability Improvement Working Groups for each of the five major plant areas outlined in this report:

Steam Generator
Turbine-Generator
Electrical
Balance-of-Plant
Converter Station

These Working Groups should incorporate the key personnel from all of the plant departments. They should meet as needed, but no less than twice per year to review the recent events that affected availability, to perform failure analysis, discuss plans for future capital improvements, and to develop suggestions for improvement in any Maintenance or Operational activity.

The results from these meetings should be added to the tracking lists, evaluated and monitored similar to the way the original suggestions are being handled.

This report covers only the activities of Steps 1 and 2. All other activities will be reported on at a later date.

Steam Generator Systems

Description of Systems

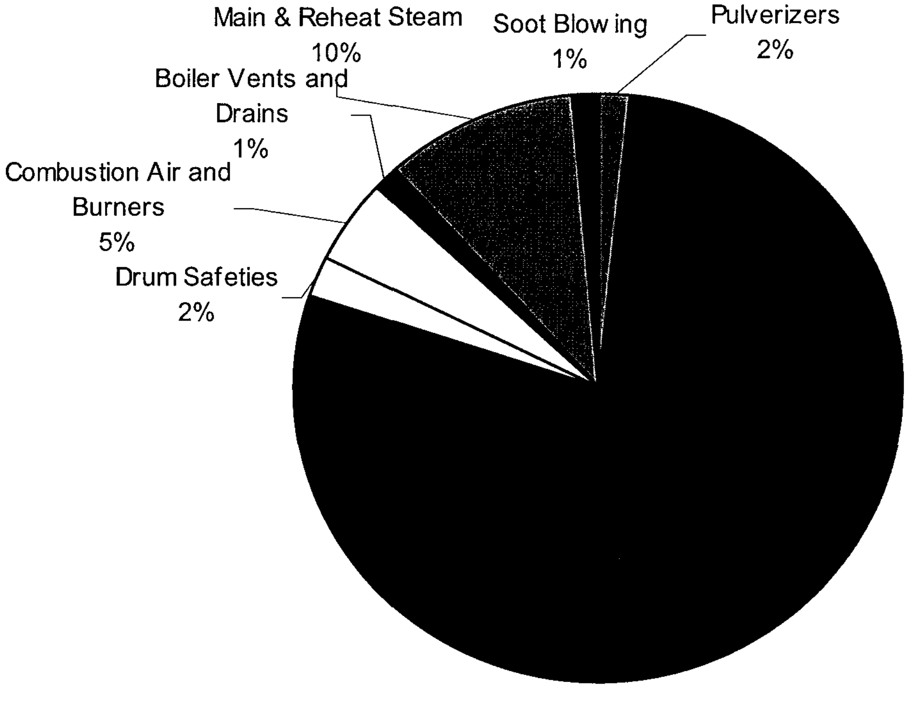
The Steam Generator System consists of the Boiler, Main Steam, Reheat Steam, Pulverizers, Combustion Air Supply, and all other subsystems necessary to generate the steam for the Turbine-Generator. For this analysis, Steam Generator, consisting of subsystems determined to be Criticality 1 or 2, were reviewed by a committee of those personnel who are responsible for these systems.

The following System Codes were analyzed with the Steam Generator Systems:

Plant System	System Code
Steam Generator	SGA
Combustion Air Supply	SGB
Boiler Vents and Drains	SGF
Main Steam	SGG
Burner and Mill Controls	SGH
Soot Blowing	SGI
Reheat Steam	SGJ

Steam Generator Losses by Subsystem

(Percentage of all Steam Generator Losses of Equivalent Availability)



Losses of Availability

Historically, the Steam Generator Systems have attributed to 44 percent of the total losses of availability for the station. IGS experiences compare very similarly to NERC-GADS data for unit downtime with the average for plants greater than 300 MW from 1995 to 1999 being 52 percent of all losses of availability. IGS is also similar to NERC-GADS with the majority of outages being caused by Boiler tube leaks (79 percent). The second largest cause of loss of availability is Main and Reheat Steam (10 percent) with most of those incidents being caused by safety valves. All other systems account for the remaining 11 percent of losses.

Some of the key statistics gathered from an analysis of the IGS historical data:

	Unit 1	Unit 2	Station
Number of events caused by Steam Generator Systems	136	130	266
Percentage fo all events caused by Steam Generator Systems	27.5%	30.1%	28.7%
Number of forced outages caused by Steam Generator Systems	33	34	67
Percentage of all forced outages caused by Steam Generator Systems	21.0%	24.3%	22.6%
Equivalent hours of lost generation caused by Steam Generator Systems	1691.1	1551.2	3242.4
Percentage of all equivalent hours of lost generation caused by Steam Generator Systems	45.9%	41.2%	44.0%

Boiler Tube Failure Reduction Program

From the initial startup of IPP, IPSC has pursued an ambitious condition assessment program for the Steam Generator and ancillary equipment. This program is designed to minimize both the average annual outage rate associated with steam generator pressure component failures (primarily tube leaks) and in minimizing the length of the respective outages.

The Boiler Tube Failure Reduction Program has yielded excellent results for the past 18-plus years at IGS. However, as the units age, the number of tube failures is trending upward. Vigilance in adhering to established standards and continuous efforts to improve the program will be necessary to maintain this high level of performance into the future.

IGS Performance Compared to Other Coal-fired Units of Similar Size

Compared with the most recent data (published January 2005) from the NERC-GADS Industry Database, the IGF units consistently out-perform the industry average when it comes to both the average number of tube-leak related outages and the average duration of respective outages. The following table summarizes these numbers compared to similar coal-fired units in the 800-1000 MWg range. Included as an attachment to this report are detailed charts showing yearly tallies for each unit in each of the categories below for each year since start-up.

	NERC-GADS 5-year Average	Unit #1 5-year Average ('00 to Present)	Unit #2 5-year Average ('00 to Present)	IGS 5-year Average ('00 to Present)
Number of tube-leak related Outages/year	3.39	1.9	1.23	1.3
Hours per Outage	174.21	102.11	57.14	64.1

On the average, IGS has managed to hold down both the number or tube-leak related outages and the outage duration to nearly 1/3 of the industry average for 18 years. However, the number of tube leaks on both units has started to climb in recent years. This is an indication of not only the increasing age of the units but of the need to improve efforts to eliminate failures. The key to reducing BTFs is to identify the failure mechanisms and take action to mitigate or eliminate the root causes.

Historical BTF Mechanisms

IGS Units have experienced 47 tube failures (combined) in the past 18-plus years. A brief treatment of the top three categories of failure mechanisms, and other considerations will follow as outlined below:

- Attachment-weld Failures
- External Erosion
- Short-term Overheat
- NO Water Chemistry-related tube failures
- Other Mechanisms of Concern

Attachment-weld Failures
More than 20 percent of all tube failures at IGS have resulted from failure of dissimilar-metal welds at the hanger-lug attachments in the vertical section of the Reheat Superheater. Other failures of this type include cracks at membrane welds where the side-wall connects to the furnace sloped floor and similar cracking at the paddle-tie bars in the corners of the furnace and at the convection-pass front wall, side wall, floor connections. These are all high stress areas. Failures are related to expansion/contraction design issues.

External Erosion
This category includes the mechanisms of Soot-blower Erosion and Flyash Erosion. Although soot-blower erosion is extensive in both units, most soot-blower related failures have resulted from soot-blower failures; failure to retract. Flyash erosion is a relatively new mechanism at IGS. Recent fuel changes have increased the ash loading through the boiler which has accelerated erosion.

Short-term Overheat
Short-term overheat normally results from restricted steam flow through the tubes. Restrictions have included weld wire, slag, exfoliated oxide, possible water blockage at start up, and most recently, a hinge pin from a check valve that made its way to a super heater inlet manifold. The ubiquitous use of chill rings, or backing rings in the weld joints of the superheater and reheat superheater tubes has provided numerous opportunities to collect debris.

NO Water Chemistry-related Failures
The discussion of tube failure mechanisms at IGS would not be complete without trumpeting the fact that plant chemists have maintained excellent water chemistry in the boilers. In more than 18 years, neither unit has experienced a chemistry-related failure.

Other Mechanisms of Concern
Although long-term overheat (creep) has not been an issue at IGS, the units are aging and both units exhibit the typical uneven temperature profile from side to side through the superheater sections. As a result, some overheating is expected. Both of these facts make this a mechanism to watch for in the future.

Most weld and material defects should have manifested themselves by this point in the life of the units. However, cracking due to mechanical and thermal fatigue will increase as time marches on. Again, vigilance is called for.

Considerable effort has been expended in the past to mitigate and eliminate many of the concerns above. A few examples of past efforts follow in the next section.

Efforts Taken to Eliminate BTF Mechanisms

The current inspection plan for the IGS units is designed to ensure that each major component of the boiler is inspected at least once every 6 years (3 major-outage cycles). However, experience has proven to be the best guide as to where to concentrate the inspection resources. Unit 2 has a much better BTF record, in part, due to lessons learned on Unit 1. A few examples follow:

- Reheat Superheat Support Lugs
- Paddle-tie bars
- Lower Furnace Wall-to-Floor Connections
- Lower Waterwall Header Issues
- Convection Pass Arch

These are areas where numerous tube failures resulted from over-stressed connections. Failures in these areas have been reduced due to increased inspection frequency and scope, and by making alterations to relieve residual stresses.

Soot-blower damage has been reduced by forming a dedicated soot-blower crew to improve the consistency of maintenance. Soot blower pressure settings have also been optimized to find a balance between maximizing cleaning efficiency and minimizing damage. Damage maps are used to track wastage rates, and of course, tube shields are employed in troublesome areas when possible.

Flyash erosion is mitigated by careful attention to tube alignment in pendant elements and shielding/baffling is employed where needed.

It is difficult to combat short-term overheat; but, preemptive radiographic examination of lower tube bends and small diameter chill rings has been employed in the past to mitigate this mechanism.

Long-term overheating is monitored with internal oxide thickness measurements in the highest temperature areas of the pendants. Base-line data is compared to more recent readings with Larsen-Miller analysis to estimate remaining life. Replication at welds, particularly on the penthouse headers is used to spot creep in the early stages.

A more comprehensive oxide thickness survey is under consideration that would allow us to identify the tubes operating at the highest temperatures and consequently allow the installation of flow balancing hardware at the outlet headers to balance tube temperatures across the boiler.

Future efforts to minimize tube failures will be guided primarily by:

- Manufacturer recommendations
- Historical failure experience
- Internal inspection results
- Time in-service
- Location in the steam generator
- Type of material
- Operating temperature and pressure
- Design and operating stress loads

As man-power and budgetary resources are limited, efforts will be prioritized to areas that represent the highest risk of equipment damage and the most likely sources of tube-failure related outages.

Recommendations

Recommendations are classified into four main areas; Maintenance, Predictive Maintenance, Capital Projects, and Critical Spare Parts. Some of the main points are discussed below. Please refer to the complete list of recommendations for the Steam Generator Systems in the appendix. The following are the most significant items the committee felt were of greatest value to ensure continued high availability of the station. They are listed in order of the area of evaluation and not in order of importance.

Maintenance Improvements

Chill Rings for Dissimilar Thickness Tube Welds

One of the most difficult welds to complete in the boiler is one involving different thicknesses of tube materials. This can be assisted by the proper application of chill rings to hold and center the different tube materials. A Maintenance Instruction (MI) should be developed on the proper use of chill rings

Purchase Tube Bending Machine

Purchase of a tube bending machine and dies. An increase in tooling is necessary to prepare for tube leaks in areas of the boiler that have not as yet been a problem. There are many areas of the boiler that have tight radius bends in tubes. It is necessary that we are able to perform these bends for replacement of the failed tubes. An alternate plan would be to stock pre-bent tubes of all sizes needed.

Recommended Capital Projects

Replace Electromatic Relief Valves and Controls

Replace Electromatic Relief valves and controls with up-to-date technology. When these valves do not operate properly it causes the other relief valves to open. Past history has shown that the other relief valves have a history of not closing tightly after actuation. This has been a cause of lost load. It is necessary to restrict main steam pressure when these valves are "gagged" or schedule a Unit outage for the repair of these valves.

Add Drum Safety Valve

Addition of one Drum safety valve. The addition of one Drum safety valve would enable the Unit to stay at full load and pressure when one of the other safety valves has been "gagged" due to leak by.

Replace Sootblower Thermal Drains and Controls

Replacement of the sootblower thermal drain valves and controls for these valves. These valves limit the amount of moisture in the sootblowing lines. Upon start up of a sootblower, it is important that no water is present in the sootblowing lance as it starts into the boiler. The presence of water when the sootblower inserts into the boiler will mix the water with fly ash and increase sootblower/fly ash erosion in that area. This repeated occurrence will lead to boiler tube leaks.

Recommended Changes in Predictive Maintenance

Increase Boiler NDE and Inspection

Increase NDE and inspection of specific areas of the boiler. The back pass area of the boiler in the Horizontal Superheat section is an area that needs additional access for inspection. A need for a door in the back of the boiler on the middle section of Superheat tubes is necessary for the inspection of the tubes located in this area.

Recommended Additional Critical Spare Parts

FD Fan Hydraulic and Lube Oil Pumps

We have a spare rotor, motor, and most other parts in the event there is a major failure but, we do not have spare hydraulic and lube oil pumps. An evaluation should be done on the cost, availability, and risk of failure of one of these pumps. The loss of an FD Fan would be a significant derate to the facility.

PA and FD Fan Speed Changer

Both the PA and FD fans utilize two-speed motors for control and operation. We maintain a spare motor but, we do not have spare speed change switches. These switches are unusual and difficult to obtain.

Assessment of Spare Tubing

Assessment of spare tubing. It is necessary to have all of the tubing available for repairs when a tube leak has occurred. This will be addressed in several ways.

1. Determine tube needs based on history and location of probable tube leaks.

2. Establish minium stocking requirements of pre-bent tubing for specific areas of the boiler and investigate the feasability of an assured stocking program with a vendor.

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AVAILABILITY IMPROVEMENT PROJECT

Created by: Gerald K. Hintze

January 2007

Turbine Generator

Description of Systems

The turbine is a tandem-compound reheat unit consisting of a single-flow high pressure section, a double-flow reheat section, and three double-flow low pressure sections originally supplied by General Electric. The high pressure section in both Units 1 and 2 was replaced in March 2003 and March 2002 respectively with Alstom rotors, diaphragms, and inner casings as part of a performance upgrade. The last low pressure section is coupled to a two-pole, hydrogen cooled generator rotor designed for continuous operation. This system includes all supporting auxiliary equipment.

The following System Codes were analyzed with the Turbine Generator Systems:

Plant System	System Code
Turbine	TGA
Generator	TGB
Turbine Seals and Drains	TGC
Turbine Lube Oil	TGD
Generator Cooling and Purge	TGE
Turbine Controls EHC	TGF

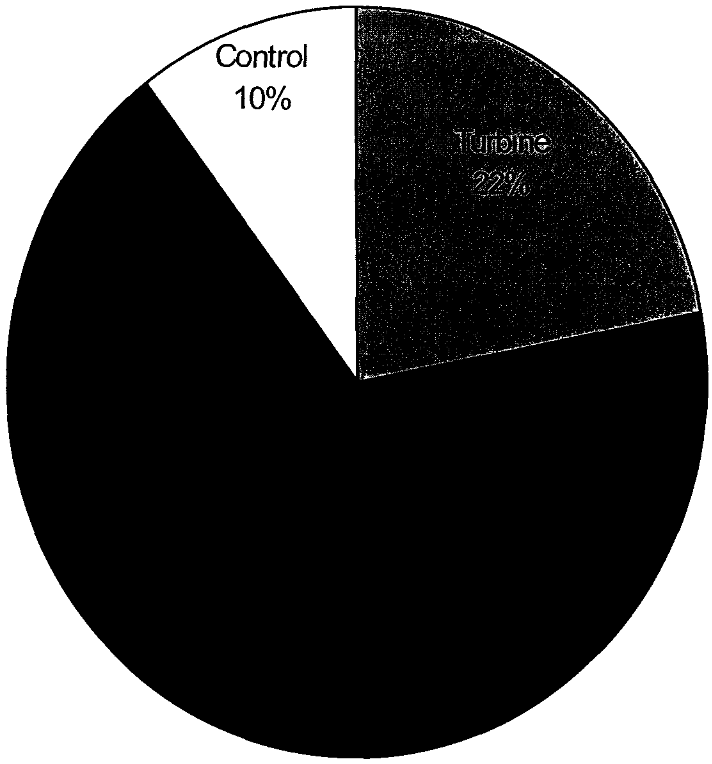
Losses of Availability

Statistics for the Turbine Generator System gathered from an analysis of the IGS historical data:

	Unit 1	Unit 2	Station
Number of Events Caused by Turbine Generator Systems	51	48	99
Percentage of All Events Caused by Turbine Generator Systems	10.3%	11.1%	10.7%
Number of Forced Outages Caused by Turbine Generator Systems	25	25	50
Percentage of All Forced Outages Caused by Turbine Generator Systems	15.9%	17.9%	16.8%
Equivalent Hours of Lost Generation Caused by Turbine Generator Systems	737.7	1391.73	2129.4
Percentage of All Equivalent Hours of Lost Generation Caused by Turbine Generator Systems	20.0%	37.0%	28.9%

Turbine Generator Losses by Subsystem

(Percentage of all Turbine-Generator Losses of Equivalent Availability)



It is significant to note that of the total 2,129.4 hours of generation loss in this system, 53 percent (1,130 hours) is attributable to the failure of the pole-to-pole jumper on the main generator field on Unit 2. The main field required a complete rewind, and extended the scheduled 1996 outage by 47 days.

There was no one type of incident that caused the majority of forced outages that originated from the turbine-generator. The most repetitive incident was failure of the turbine Electrical Trip Test system which accounted for fourteen of the fifty forced outages. The Electrical Trip System is being replaced as part of the plant DCS upgrade which should address that problem.

Generator Reliability

The generator is the heart of any power plant and an unexpected failure of the generator can result in months, or possibly years, of downtime. There are many known failure mechanisms in a generator, some electrical in nature and some mechanical. Most are difficult, if not impossible, to monitor or check on a regular basis. Some of the major concerns with generator reliability are:

- Field Turn-to-Turn Shorts
- Leaking Stator Bars and Insulation Integrity
- Field Pole-to-Pole Jumper Cracking
- Hydrogen Seal Integrity
- Stator Wedge Tightness

The biggest concern of all of these is leaking stator bars and insulation integrity. Capital Project IGS03-05 was originally developed to insure continued reliable operation of the generators. The original scope of the project included purchasing a spare stator winding and replacing the exciters for both units.

The spare stator winding was scheduled for purchase first because of recommendations from General Electric and continuing problems with the hydraulic integrity of the winding. However, because epoxy repairs fixed many of the initial leaks and biannual testing of the stator windings indicated this problem was progressing slowly, the replacement of the exciters was moved up in the schedule. The exciters became a higher priority because of the lack of replacement parts and technical support for the existing systems.

In addition, in the Spring of 2005, the Unit 1 generator field developed a turn-to-turn short. This short limits the reactive capability of the generator due to vibration caused by thermal sensitivity of the field rotor.

The money originally allocated to purchase spare stator bars will be used to rewind the Unit 1 field. A separate capital purchase was submitted, for the 2007-2008 budget, to purchase the spare stator winding.

The current schedule for generator modifications is:

Complete Tuning of New Unit 2 Excitation System	Spring 2006
Replace Unit 1 Excitation System	Spring 2007 Outage
Rewind the Unit 1 Generator Field	Spring 2007 Outage
Purchase of Spare Stator Winding (multi-year)	July 2007 - June 2008

The generator excitation system replacement and spare stator winding project, IGS03-05, was developed to maintain the reliability of the generators.

The original project budget included:

System Studies and Specification Preparation	2003 - 2004	$ 85,000
Purchase and Install Unit 1 Excitation System	2004 - 2005	$3,760,000
Purchase and Install Unit 2 Excitation System and Purchase Spare Stator Winding	2005 - 2006	$7,560,000

The revised budget includes:

Unit 1 Excitation System	2006-2007	$3,000,000*
Unit 1 Field Rewind	2006-2007	$2,000,000
Spare Stator Winding	2007-2008	$5,000,000

* includes $2,000,000 carried over from the 2005-2006 because of late equipment deliveries.

We started reviewing the performance of the generator stator windings based on a TIL (technical information letter) from General Electric in 1991. Early on, we determined we had a significant problem with the hydraulic integrity of the stator windings. Global epoxy repairs of the windings in 1996 (Unit 2) and 1997 (Unit 1) significantly improved the winding integrity, but we continue to have problems passing the GE recommended vacuum and pressure tests on the stator winding.

After we started evaluating the reliability of the generators, it became apparent that within a few years we would need to replace the excitation systems on both units. The current generator excitation system is no longer manufactured by General Electric (GE). GE is still providing parts, as the components are available from their suppliers, but there is limited field support from personnel with Generrex experience. Recently, GE was unable to supply replacement bridge disconnect switches and field current transducers because of component obsolescence. We have had ongoing problems with drifting field current transducers, misaligned DC field circuit breakers, and intermittent connections on the bridge disconnects for both units. In addition, we have had intermittent control power supply grounds on the trip circuit bus on Unit 2. We currently stock critical spare parts for most of the Generrex controls, but we do not have any spare parts for the components in the generator dome.

There are less than 30 compound source Generrex systems in service and through discussions with other Generrex owners, it is apparent that continued reliable operation of these units is not feasible. After our evaluation, we decided to delay the purchase of the spare stator bars until after the Unit 2 exciter was replaced.

In 2005, a new concern was identified for long term reliable operation of the generators. Testing after the Unit 1 Spring 2005 outage indicated the field had developed a turn-to-turn short. This short was apparently causing thermal sensitivities in the field. The turn-to-turn short was discovered due to generator vibrations at varying field current conditions and was confirmed through flux probe testing. Plans were then made to rewind the Unit 1 field in 2007. In order to minimize impact to the capital budget, caused by the cost of rewinding the field, the stator bar purchase was postponed.

In 2006, at the start of the Unit 2 outage, additional flux probe testing was performed on both units. The Spring 2006 test on Unit 1 indicates there may not be a turn-to-turn short in the field. In the Fall of 2006, an independent consultant, GeneratorTech confirmed the presence of the turn-to-turn short. Based on these results, we plan to rewind the Unit field in the Spring 2007 Outage.

Recommended Capital, Predictive, or Maintenance Improvements

The following is a list of significant items recommended by the committee to ensure continued high availability of the station. They are listed in order of the primary system and not in order of importance.

Continue with industry standard nondestructive examinations of turbine rotors at scheduled outages.

All of the intermediate and low pressure turbine rotors have had boresonic inspections completed. Nothing of significance has been noted. The recommendation is to continue with boresonic inspections every 7 to 10 years. Boresonic testing has not been done on the Alstom high pressure turbine rotors. Additionally, ultrasonic (UT) examinations have been completed on the L-1, L-2, and L-3 wheel dovetails. UT testing has been completed on the L-0 finger dovetail pins as well. Physical measurements of the rotor bucket dovetail lifting have been taken on the L-0, L-1, L-2, L-3, L-4 and L-5 stages.

Review potential replacement and upgrade of the intermediate and low pressure turbine rotors.

The intermediate pressure (IP) turbine and low pressure (LP) turbine rotors should be reviewed for replacement based on design and metallurgy improvements. Replacement of the rotors would require performance and economic justification.

Upgrade turbine bearing pedestal monitoring system.

Pedestal heights on turbine bearings T-1 through T-11 are monitored using a system of Invar rods and proximity probes. The system provides valuable information on changes in bearing pedestal height useful when making decisions on turbine alignment. The system should be upgraded to include the latest technology and to include indication on the T-12 and T-13 bearing pedestals.

Purchase spare condenser expansion joint.

The connection between the LP hoods and the condenser consists of a stainless steel bellows expansion joint. The committee recommends the purchase of a complete replacement for at least one (1) condenser. This would include the purchase of four (4) corner pieces that require welding to the straight runs of expansion joint to complete the assembly.

Upgrade the generator core monitoring system.

The core monitoring system should be upgraded to the latest technology. New monitoring systems, such as Partial Discharge Analysis, should be evaluated for installation.

Purchase spare Main Seal Oil pump and motor.

The Hydrogen Seal Oil system includes the Main Seal Oil pump (MSOP), Recirc Seal Oil pump (RSOP), and the Emergency Seal Oil pump (ESOP). The MSOP is the primary source of sealing oil for the main generator and is critical equipment. The ESOP will provide emergency back up for the MSOP, however the committee feels it is prudent to have a spare MSOP available for quick replacement when needed. The same applies for the MSOP motor.

The EHC skid should be evaluated for upgrade and replacement.

The EHC skids have redundant 100 percent capacity pumps, and we also stock spare pumps in the warehouse. However, the pump and skid design itself should be evaluated and upgraded. New systems are available, such as a "Turbo-Toc" system, and should be considered for installation. Additionally, the stocking levels of EHC fluid should be reviewed and a 100 percent capacity change out should be considered.

Purchase and stock a spare Stator Cooling Water Pump.

The stator cooling water skid includes redundant 100 percent capacity cooling water pumps. The pumps can be replaced on-line and this has been done in the past.

However, when one pump is out of service and taken to the shop for maintenance, all redundancy is lost. We stock parts to rebuild the stator cooling water pumps, but having a complete pump available for immediate installation when an in-service pump fails would reduce our chances of lost generation. Additionally, we should stock a spare motor for these pumps as well.

Install an additional auxiliary overhead crane on the main turbine deck cranes.

There are two (2) overhead bridge cranes used for turbine and generator maintenance. Each crane has a 95-ton hook and a 40-ton hook. The committee feels that some turbine repair work could be completed in a more expeditious manner if an additional crane, of smaller capacity, could be installed on the existing bridges. Many of the lifts made during turbine repairs are well under the capacity of even the 40-ton crane. Having a smaller capacity crane available, in the 10 to 15 ton range, would aid Maintenance in completing turbine and boiler feed pump work.

Presentation on Availability Improvement and Critical Spare Parts - Jerry Hintze gave a presentation and hand-out about an on-going project to improve plant availability and insure that we have the critical spare parts necessary to maintain the units. The presentation covered the historical losses of availability with information on what systems and equipment have caused those losses. The number one factor for maintaining availability will be controlling boiler tube leaks followed by generator, transformer and boiler feed pump controls reliability. More emphasis needs to be placed on spare parts for the Converter Station also.

Status of Availability Improvement Project - May 7, 2007

Because of the Unit 1 outage, the Availability Improvement Project Team did not meet in March or April. The next meeting is scheduled for May 16, 2007. At the last meeting in February, we determined that we needed to prioritize the suggestions and then start evaluating the suggestions in detail after the Unit 1 outage.

A priority code system was developed after the February meeting (attached). Prior to the next meeting, each member of the team is supposed to evaluate the recommendations and assign their recommended Priority Code for that suggestion. When we next meet, we will come to a consensus on the highest priority suggestions and then we will assign someone to complete a detailed economic and feasibility assessment of that suggestion. We will have the Priority 1 evaluations completed by the end of July so they can be reviewed and placed on the 2008-09 budget if justified.

IPSC

INTERMOUNTAIN POWER SERVICE CORPORATION

IPSC AVAILABILITY IMPROVEMENT PROJECT

Number:	HRD-2	**Reviewer:**	Jerry Hintze	**Status:**	Open
Initiation Date:		12/2006		**Priority Code:**	1
System Code:	HRD	**System Description:**	Circulating Water Make-up	**Type of Suggestion:**	Capital Project

Description: Insure integrity of the 30" supply line from Water Treatment to the Cooling Tower Basins.

Evaluation Method: Called Pressure Pipe Inspection Company and discussed options for testing this pipeline. Because of size, manned entry is not possible and there are no manholes for inserting a robot probe easily. Inspection would require a 1-2 week outage and removal of metered run and section of pipe at water treatment. This can be done using the bypass line at the cooling towers and supplying water direct from the On-Site Reservoir to both units.

This pipe is cylinder wrapped C301 prestressed concrete cylinder pipe manufactured by the same supplier as the failed surface water supply line. The probability of a failure is high. Failed sections should be identified and repaired. The pipeline should also be tested for electrical continuity and cathodic protection installed if possible.

Recommendation: Funds should be placed on the next available budget cycle for inspection of this pipeline. Acid supply will have to be coordinated with suppliers to insure we have adequate for the test period.

Estimated Cost of Recommendation: $125,000

Status Notes: On hold pending placement and approval on the 2008-09 budget

Completion Date:

5/21/07 jmj

Outline of Report on Availability Improvement Project

Executive Summary

Description of Project
List of Additional Capital, Predictive or Maintenance Improvements
List of Recommended Additional Spare Parts

Introduction

Purpose of Project
Historical Losses of Availability
Rationale for Critical Systems
List of Critical Systems

Steam Generator

Description of System
Breakdown on Losses of Availability
Available and Current Methods of Predictive Maintenance
Maintenance Methods and Philosophies.
Recommended Additional Capital, Predictive or Maintenance Improvements
Recommended Additional Spare Parts

Turbine Generator

Description of System
Breakdown on Losses of Availability
Available and Current Methods of Predictive Maintenance
Maintenance Methods and Philosophies.
Recommended Additional Capital, Predictive or Maintenance Improvements
Recommended Additional Spare Parts

Electrical Systems

Description of System
Breakdown on Losses of Availability
Available and Current Methods of Predictive Maintenance
Maintenance Methods and Philosophies.
Recommended Additional Capital, Predictive or Maintenance Improvements
Recommended Additional Spare Parts

Balance of Plant

Description of System
Breakdown on Losses of Availability
Available and Current Methods of Predictive Maintenance
Maintenance Methods and Philosophies.
Recommended Additional Capital, Predictive or Maintenance Improvements
Recommended Additional Spare Parts

Converter Station

Description of System
Breakdown on Losses of Availability
Available and Current Methods of Predictive Maintenance
Maintenance Methods and Philosophies.
Recommended Additional Capital, Predictive or Maintenance Improvements
Recommended Additional Spare Parts

Appendix:

List of Recommendations

Complete of plant System with Criticality Codes

Explanation of FERC Types and Events

List of Availability Incidents by System

10-Year Capital Budget

Agenda
Availability Assurance Project
November 27, 2006

1. Results of availability study
   Graphs of historical availability losses
2. Criticality assessment
3. Process for reviewing spare parts of critical systems
4. Action items and schedule
5. Other items
6. Next meeting

Agenda
Availability Assurance Project
Steam Generator Systems Evaluation

1. Goals of Availability Assurance Project

2. Determination of Critical Plant Systems
   a. History of Availability Losses
   b. Criticality Codes

3. Review of Steam Generator System (SGA System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

4. Review of Combustion Air Supply System (SGB System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

5. Review of Boiler Vents and Drains (SGF System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

6. Review of Main Steam (SGG System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

7. Review of Burner and Mill Controls (SGH System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

8. Review of Sootblowing (SGI System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

9. Review of Reheat Steam (SGJ System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

10. Review of Action Items, Schedule for Completion

11. Other Items

Availability Assurance Project

12/12/06 Review Meeting Update

Generator Terminal (GT) System

Subsystem: GTA – Generator Bus Duct

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Review Generator Breaker replacement schedule and improve delivery for the first unit. Could use parts removed from one unit to serve the second unit.			Breaker obsoleted in 1999. Parts availability is diminishing.
Add viewing windows at all Iso-Phase connnection joints to improve thermography capability with unit on line.			
Add infrared detection montioring system on Iso-Phase bus duct.			

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase spare Iso-Phase bus duct jumper sections in case of breaker pole failure. Includes connecting braids and shunts.			Sync control moved to ICS if this scenario occurs.
Review spare parts for the Generator PT and Transformer PT & Surge cubicles.			

Subsystem: GTB – Generator Transformer

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase and install GSU Transformer oil continuous dissolved gas analysis monitoring system.			
Purchase and install new digital temperature monitoring system for installation on U1 & U2 GSU Transformer.			
Fully dress and test the spare GSU and Aux Transformers. Install bushings, bushing pockets, and CTs.			This would deplete the spare bushings currently in stock and would necessitate purchase of new high, low, and neutral bushings for stock.

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase spare neutral grounding resistor bank.			Catastrophic failure of a GSU Transformer would likely cause loss of resistor bank due to proximity.
Review warehouse spare stocking level on GSU surge arresters	Kevin-M		
Review spare parts stocking level on external CTs mounted on GSU high side bushings.	Kevin-M		
Review spare parts stocking level on complete gasket set for GSU	Kevin-M		

ICS Controls (COX)

Description of Systems

The ICS Controls Systems consist of all control systems that control the Rectifier process, the Station protections, Filter protections and Raw and Fine Water Controls. All of these systems are fully redundant and spares are provided for each of the circuit boards and interpose relays. Because of this redundancy, the control systems have a Criticality ranking of 3.

The following System Codes were analyzed with the Control Systems.

Control System	System Code
Bipole Controls	COX-B
Pole 1 Controls	COX-1
Pole 2 Controls	COX-1
Station Controls	COX-ST
Filter Controls	COX-STA

Recommended Spare Parts

- 1 complete set of Circuit Boards, Terminal Boards, and Processor Boards that can be used to replace any type of board required for the Bipole Controls, Pole 1 Controls, Pole 2 Controls, Station Controls and Protections, and Filter Controls and Protections.

- 1 complete set of Control/Protection Transducers and Meters to match any type used in the control systems as stated above.

- 1 complete set of Control/Protection Relays to match each type of relay required as above.

- 1 Complete set of Fiber Optic terminals for the Optical Current Transducer modules.

Note: The Criticality ranking of 3 is because of the full redundancy. These Systems are critical for the operation of the Converter Station. Therefore, 1 spare type of each set of Circuit Boards, Transducers, Meters, and Relays maintains the redundancy.

ICS Pole 1 Equipment (P1DC)

Description of Pole 1 DC System

The Pole 1 DC System consists of all the equipment necessary to convert alternating current to direct current and the bus-work and equipment necessary to provide a reliable, reconfigurable connection path for bipolar/monopolar and metallic/ground operation between the HVDC valve halls and each end of the transmission line at Intermountain and Adelanto. The DC Pole 1 equipment at each station can be divided into six groups, consistent with their functionality. These groups are (1) switching equipment, including breakers and disconnect switches, (2) protective devices to limit transient currents and voltage surges, (3) filters to reduce harmonic current and carrier and radio interference, (4) converter transformers and thyristor valve modules for AC to DC conversion, (5) measuring transducers for current and voltage levels, and (6) heat exchangers, motors, and pumps to remove excess heat from the thyristor valves.

The following System Codes were analyzed with the Pole 1 DC systems.

Pole 1 Systems	System Code
Pole 1 High Voltage Bus	P1DC-H
Pole 1 Neutral Bus	P1DC-N
Pole 1 DC Filters	P1DF
Pole 1 Valve Hall	P1VH
Pole 1 AC Yard	P1AC
Pole 1 Fine Water Cooling	P1FW
Pole 1 Raw Water Cooling	P1RW

Although this equipment is redundant or reconfigurable, loss of one or more components may cause partial load loss and is therefore given a Criticality 2 ranking.

Recommended Spare Parts

(High Voltage Bus, P1DC-H)

- 1 complete Disconnect Switch, including insulator stacks and grounding switch for 1H/2H.
- 1 complete set of components for CCP1.H.
- 1 set of spare components for Arrester, DCT, Reactor, Line Trap, and Voltage Divider.
- 1 set of spare Connectors for bus-work and 2 sets of spares for each type of line connection.

(Neutral Bus, P1DC-N)

- 1 set of spare components for Arrester, DCT, Line Trap, Voltage Divider, Capacitor Stack.
- 1 complete spare Circuit Breaker for use at 1N, 2N, 1E, or 2M.

- 1 complete spare Neutral Disconnect Switch.
- 1 spare Insulator of each type used on Neutral Bus.

(DC Filters, P1DF)

- Recommend taking Filter Bank 2 or 3 Out-Of-Service and keeping it as a cold spare which can be tuned as either a 12^{th} or 24^{th} Harmonic Filter.

(Valve Hall, P1VH)

- 1 new Valve Test Unit
- Maintain discrete components at 5 percent spares level for Thyristor Valve.
- 1 complete spare set of PEX tubes and connectors.
- 1 complete Thyristor Valve Module ready for service.

(AC Yard, P1AC)

- 1 complete spare Converter Transformer
- 1 complete set of spare Contactors for 1 Cooler Group.
- 1 spare Bucholz Relay
- 1 set of spare Bladders for each type needed for conservator tanks kept under N2.
- 1 set of spare Connectors for bus-work and 2 sets of spares for each type of line connection.
- 1 set of spare CVTs and CTs for each type needed.
- Maintain 5 percent spares for capacitors and reactors needed in PLC yards.

(Fine Water, P1FW)

- 1 set of spare fittings for heat exchangers, pipes, pumps, and valves.
- 1 complete set of spare gaskets for a heat exchanger.
- 1 set of spare valve handles for each type needed in fine water cooling system.

(Raw Water, P1RW)

- 1 spare pump, motor, and valve for each type needed in raw water cooling system.

Recommended Additional Capital, Predictive or Maintenance Improvements

- Perform Furans testing on all oil-impregnated-paper insulated equipment.
- Install transformer on-line monitoring for Doble Insulator Testing and Dissolved Gas Analysis.
- Modify cooling equipment crane/hoist rails to position directly overhead the heavy equipment.
- Install bypass piping and small ball valve on fine water filter tank.
- Replace existing cooling towers due to end-of-service-life and obsolescence.

ICS Pole 2 Equipment (P2DC)

Description of Pole 2 DC System

The Pole 2 DC System consists of all the equipment necessary to convert alternating current to direct current and the bus-work and equipment necessary to provide a reliable, reconfigurable connection path for bipolar/monopolar and metallic/ground operation between the HVDC valve halls and each end of the transmission line at Intermountain and Adelanto. The DC Pole 2 equipment at each station can be divided into six groups, consistent with their functionality. These groups are (1) switching equipment, including breakers and disconnect switches, (2) protective devices to limit transient currents and voltage surges, (3) filters to reduce harmonic current and carrier and radio interference, (4) converter transformers and thyristor valve modules for AC to DC conversion, (5) measuring transducers for current and voltage levels, and (6) heat exchangers, motors, and pumps to remove excess heat from the thyristor valves.

The following System Codes were analyzed with the Pole 2 DC systems.

Pole 2 Systems	**System Code**
Pole 2 High Voltage Bus	P2DC-H
Pole 2 Neutral Bus	P2DC-N
Pole 2 DC Filters	P2DF
Pole 2 Valve Hall	P2VH
Pole 2 AC Yard	P2AC
Pole 2 Fine Water Cooling	P2FW
Pole 2 Raw Water Cooling	P2RW

Although this equipment is redundant or reconfigurable, loss of one or more components may cause partial load loss and is therefore given a Criticality 2 ranking.

Recommended Spare Parts

(High Voltage Bus, P2DC-H)

- 1 complete Disconnect Switch, including insulator stacks and grounding switch for 1H/2H.
- 1 complete set of components for CCP1.H.
- 1 set of spare components for Arrester, DCT, Reactor, Line Trap, and Voltage Divider.
- 1 set of spare Connectors for bus-work and 2 sets of spares for each type of line connection.

(Neutral Bus, P2DC-N)

- 1 set of spare components for Arrester, DCT, Line Trap, Voltage Divider, Capacitor Stack.
- 1 complete spare Circuit Breaker for use at 1N, 2N, 1E, or 2M.

- 1 complete spare Neutral Disconnect Switch.
- 1 spare Insulator of each type used on Neutral Bus.

(DC Filters, P2DF)

- Recommend taking Filter Bank 2 or 3 Out-Of-Service and keeping it as a cold spare which can be tuned as either a 12^{th} or 24^{th} Harmonic Filter.

(Valve Hall, P2VH)

- 1 new Valve Test Unit
- Maintain discrete components at 5 percent spares level for Thyristor Valve.
- 1 complete spare set of PEX tubes and connectors.
- 1 complete Thyristor Valve Module ready for service.

(AC Yard, P2AC)

- 1 complete spare Converter Transformer
- 1 complete set of spare Contactors for 1 Cooler Group.
- 1 spare Bucholz Relay
- 1 set of spare Bladders for each type needed for conservator tanks kept under N2.
- 1 set of spare Connectors for bus-work and 2 sets of spares for each type of line connection.
- 1 set of spare CVTs and CTs for each type needed.
- Maintain 5 percent spares for capacitors and reactors needed in PLC yards.

(Fine Water, P2FW)

- 1 set of spare fittings for heat exchangers, pipes, pumps, and valves.
- 1 complete set of spare gaskets for a heat exchanger.
- 1 set of spare valve handles for each type needed in fine water cooling system.

(Raw Water, P2RW)

- 1 spare pump, motor, and valve for each type needed in raw water cooling system.

Recommended Additional Capital, Predictive or Maintenance Improvements

- Perform Furans testing on all oil-impregnated-paper insulated equipment.
- Install transformer on-line monitoring for Doble Insulator Testing and Dissolved Gas Analysis.
- Modify cooling equipment crane/hoist rails to position directly overhead the heavy equipment.
- Install bypass piping and small ball valve on fine water filter tank.
- Replace existing cooling towers due to end-of-service-life and obsolescence.

Station AC Switchyard Equipment (SWE)

Description of AC Switchyard Equipment

The Intermountain Station AC Switchyard serves as a switching point to the AC system in Utah via two 345-kV AC transmission lines to the Mona Substation, to the AC system in Nevada via one 230-kV AC transmission line to the Gonder Substation, to the two AC generators at Intermountain, to the two HVDC converters at Intermountain, and to the three AC filter banks also located adjacent to the AC Switchyard at Intermountain. Complete isolation for these connections is made by way of circuit breakers, disconnects, and grounding switches.

The following System Codes were analyzed with the AC Switchyard Equipment.

Switchyard Systems	System Code
345 kV Bus 1 and Bus 2	SWE-0
B Rack 46 kV	SWE-1
Bank M Gonder	SWE-2
Position E5 - Gonder	SWE-5
Position E6 - Filter Bank 3	SWE-6
Position E8 - Filter Bank 2 and Pole 2	SWE-8
Position E9 - Aux Bank L and Unit 2	SWE-9
Position E10 - Aux Bank K and Unit 1	SWE-10
Position E11 - Filter Bank 1 and Pole 1	SWE-11
Position E12 - Mona 1	SWE-12
Position E13 - Mona 2	SWE-13

Except for Bank M, this equipment is redundant through a breaker-and-a-half scheme. Loss of any single piece of equipment for all positions except Bank M would result in a Criticality 3, and loss of equipment for Bank M (Gonder) would be a Criticality 2 factor.

Recommended Spare Parts

- 1 set of spare conductor connectors for bus-work and 2 sets of spares for each type of line connection.
- 1 complete 3-phase spare of the Westinghouse 345 kV breaker
- 1 complete phase spare of the Mitsubishi 345 kV breaker
- 1 complete spare 345 kV disconnect
- 1 complete spare 46 kV breaker
- 1 complete spare 46 kV disconnect
- 1 complete set of spare 46 kV fuses for each type of fuse.
- 1 complete set of spare CVTs and CTs for 345 kV, 230 kV, and 46 kV busses.
- 1 set of spare 46 kV potheads.
- 1 set of spare cable splice kits for all cable sizes.

Station AC Filters (STA)

Description of AC Filter Equipment

The Intermountain Station AC Filter Banks absorb the odd harmonic currents generated by the converters. They also contribute to balancing the reactive power consumption of the converters. At low DC power levels, the needed filters could cause overcompensation. In order to prevent this, the filter banks are complemented with a shunt reactor in each filter bank. The filter banks also help maintain AC system stability.

The following System Codes were analyzed with the AC Filter Bank Equipment.

Filter Systems	System Code
AC Filter Bank 1	STA 1
AC Filter Bank 2	STA 2
AC Filter Bank 3	STA 3

As originally designed, two AC filter banks provided the necessary harmonic current filtering and the reactive power required by the HVDC converter bipole. The third AC filter bank was a redundant backup to allow maintenance for any one filter bank when required.

Pursuant to the uprate of the Intermountain generation units, all three AC filter banks are now required to be in service to maintain proper switchyard voltage and to balance the reactive power consumption. Therefore, losing any AC filter bank imposes a Criticality 2 factor for availability.

Recommended Spare Parts

- 5 percent spare capacitors for each capacitance value in the sub-bank filters.
- 3 spare reactors for the 11/13 sub-bank filter.
- 3 spare reactors for the 3/5/7 sub-bank filter.
- 1 spare CT for each type in the Filter Bank.

Recommended Additional Capital, Predictive or Maintenance Improvements

- Install monitoring equipment to measure on-line filter performance.
- Purchase a capacitor bridge test unit to check capacitance of each sub-bank filter.

ICS Auxiliary Power (APX)

Description of ICS Auxiliary Power

The auxiliary power at ICS consists of four independent supply transformers, each of which can supply the entire auxiliary power load for the converter station. Two are generally in service, each feeding a different supply bus. The supply bus then feeds transformers that supply the 480 volt busses. Each piece of equipment is fed from these dual busses. The loss of power at any point in the system will thus result in a transfer to an alternate bus or source.

The AC Relay House has 3 independent supply transformers, each of which can supply the entire auxiliary power load of the relay house. Two are generally in service, each feeding a different supply bus. The supply bus then feeds transformers that supply the 480 volt busses. Each piece of equipment is fed from these dual busses. The loss of power at any point in the system will thus result in a transfer to an alternate bus or source.

All equipment is redundant, and the loss of any part of the system will not result in load loss, and is therefore given a Criticality of 3. This system is a vital component for the running of the Intermountain Converter Station and Intermountain Relay House and AC Switchyard.

Battery systems for the Converter Station consist of two independent 125 VDC battery systems with redundant chargers, two 48 VDC battery systems with redundant chargers, and two 24 VDC battery systems with redundant chargers. These systems are Criticality 3 because of redundancy.

Battery systems for the AC Relay House consist of two independent 250 VDC battery systems with redundant chargers, and two 48 VDC battery systems with redundant chargers. These systems are also Criticality 3 because of redundancy.

Recommended Spare Parts

- 1 complete set of spare circuit boards and other discrete components required in each separate type of battery chargers.

Recommended Additional Capital, Predictive or Maintenance Improvements

- Replace all batteries and chargers because of End-of-Life and obsolescence.

Agenda
Availability Improvement Project
May 16, 2007

1. Priority Codes

2. Review List of Suggestions

   Check priority code
   Assign person responsible

3. Process of evaluation

4. Schedule for completion

5. Form for reporting evaluation

6. Other Items

7. Next Meeting

Agenda
Availability Assurance Project
November 27, 2006

1. Results of availability study
   - Graphs of historical availability losses
2. Criticality assessment
3. Process for reviewing spare parts of critical systems
4. Action items and schedule
5. Other items
6. Next meeting

Agenda
Availability Assurance Project
Balance of Plant Systems Evaluation

1. Goals of Availability Assurance Project

2. Determination of Critical Plant Systems
   a. History of Availability Losses
   b. Criticality Codes

3. Review of Compressed Air (CAB System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

4. Review of Induced Draft (CCE System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

5. Review of Equipment Cooling (ECB System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

6. Review of Feedwater (FWA System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

7. Review of Heat Rejection (HR System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

8. Review of Action Items, Schedule for Completion

9. Other Items

Agenda
Availability Assurance Project
Converter Station Systems

1. Goals of Availability Assurance Project

2. Determination of Critical Plant Systems
   a. History of Availability Losses
   b. Criticality Codes

3. Review of Bipole Common - Electrode (B1DC System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

4. Review of Pole 1 System (P1DC System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

5. Review of Pole 2 (P2DC System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

6. Review of AC Filters (STA1,2 & 3 System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

7. Review of AC Switchyard (SWE System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

8. Review of Action Items, Schedule for Completion

9. Other Items

Agenda
Availability Assurance Project
Electrical Systems Evaluation

1. Goals of Availability Assurance Project

2. Determination of Critical Plant Systems
   a. History of Availability Losses
   b. Criticality Codes

3. Review of Auxiliary Power System (AP System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

4. Review of Generator Terminal System (GT System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

5. Review of Primary Power Supply (PP System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

6. Review of Action Items, Schedule for Completion

7. Other Items

Agenda
Availability Assurance Project
Steam Generator Systems Evaluation

1. Goals of Availability Assurance Project

2. Determination of Critical Plant Systems
   a. History of Availability Losses
   b. Criticality Codes

3. Review of Steam Generator System (SGA System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

4. Review of Combustion Air Supply System (SGB System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

5. Review of Boiler Vents and Drains (SGF System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

6. Review of Main Steam (SGG System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

7. Review of Burner and Mill Controls (SGH System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

8. Review of Sootblowing (SGI System Codes)
    a. Critical Equipment and Components
    b. Predictive Methods
    c. Maintenance Methods
    d. Spare Parts
    e. Action Items and Recommendations

9. Review of Reheat Steam (SGJ System Codes)
    a. Critical Equipment and Components
    b. Predictive Methods
    c. Maintenance Methods
    d. Spare Parts
    e. Action Items and Recommendations

10. Review of Action Items, Schedule for Completion

11. Other Items

Agenda
Availability Assurance Project
Turbine - Generator Systems Evaluation

1. Goals of Availability Assurance Project

2. Determination of Critical Plant Systems
   a. History of Availability Losses
   b. Criticality Codes

3. Review of Turbine System (TGA System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

4. Review of Generator and Excitation (TGB System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

5. Review of Turbine Seals and Drains (TGC System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

6. Review of Generator Cooling (TGE System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

7. Review of Turbine Controls and Instrumentation (TGF System Codes)
   a. Critical Equipment and Components
   b. Predictive Methods
   c. Maintenance Methods
   d. Spare Parts
   e. Action Items and Recommendations

8. Review of Turbine Extraction (TE System Codes)
    a. Critical Equipment and Components
    b. Predictive Methods
    c. Maintenance Methods
    d. Spare Parts
    e. Action Items and Recommendations

9. Review of Action Items, Schedule for Completion

10. Other Items

Availability Assurance Project

12/12/06 Review Meeting Update

Auxiliary Power (AP) System

Subsystem: APA – AC Power Supply (120v)

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Install all spare circuit boards for UPSs into working units to prove the spare boards are good and have the right terminals on the boards.			Different generations of boards have had different terminal types making boards non-interchangable.
Create additional databases for easier access to predictive data such as oil sample data, vibration data, alignment data, and testing data.			This is a general item applying to all systems and not specifically tied to the Aux Power system.
Focus existing PM Review program conducted by Gary Judkins to focus next on all electrical systems	Gary-J		

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase complete spare switchboard interior for a PC Distribution panelboard.			This 120V system has a 600A rated bus. ITE fusible switchboards are obsolete.
Review tray cable quantities that are installed and then purchase adequate cable to cover a significant incident in which numerous cables were damaged.	Kevin-M		This is a general item applying to all systems and not specifically tied to the Aux Power system.

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Subsystem: APC – AC Power Supply (480v)

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Review impact of loss of Helper Cooling Tower electrical equipment and develop plan if there is a disruption to the power system to the Electrical Building. We have no spare transformer, bus duct, main, or tie breaker for this gear.			

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Review outdoor bus duct assemblies for Cooling Tower SUSs. Purchase spare bus duct assemblies for both SUS A11 and B11.			We have a spare SUS AKR-100 main breaker.
Purchase spare Cooling Tower SUS outdoor transformer.			

Subsystem: APE – AC Power Supply (6900v)

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Add viewing windows to switchgear lineups and switchgear loads to more fully be able to provide thermography scans on line.			
Purchase and install Aux Transformer oil continuous dissolved gas analysis monitoring system.			
Add more Aux Power distribution equipment monitor points into the PI systems for ease of remote monitoring of bus voltages, vars, harmonics, power factor, etc.			

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Evaluate spare protective relay availability for BBC Switchgear cubicles	Randy-U		
Evaluate spare parts availability for one complete switchgear cubicle including PTs, devices, shutters, etc.	Kevin-M		
Review spare parts availability for DMAD power distribution system including transformer, pole switch hardware, and terminations.			Onsite Reservoir holds 28 day supply of water with Well Pumps in service and all DMAD pumps off.

Subsystem: APH – DC Power Supply

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase and install wet cell battery continuous monitoring system for the Unit Battery 1 & 2.			

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase complete spare switchboard interior for a DC Unit Battery Distribution panelboard.			This 125VDC system has a 400A rated bus. ITE fusible switchboards are obsolete.

Subsystem: API – Essential Service AC

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase replacement Inverters for Unit 1. Use removed inverters as parts to support the Unit 2 inverters.			

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase complete spare switchboard interior for an Essentail AC Distribution panelboard.			This 120/240V system has a 225A rated bus. ITEfusible switchboards are obsolete.

Subsystem: APJ – Essential Service DC

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase and install wet cell battery continuous monitoring system for the Essential Battery.			

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments

Availability Assurance Project

12/12/06 Review Meeting Update

Generator Terminal (GT) System

Subsystem: GTA – Generator Bus Duct

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Review Generator Breaker replacement schedule and improve delivery for the first unit. Could use parts removed from one unit to serve the second unit.			Breaker obsoleted in 1999. Parts availability is diminishing.
Add viewing windows at all Iso-Phase connnection joints to improve thermography capability with unit on line.			
Add infrared detection montioring system on Iso-Phase bus duct.			

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase spare Iso-Phase bus duct jumper sections in case of breaker pole failure. Includes connecting braids and shunts.			Sync control moved to ICS if this scenario occurs.
Review spare parts for the Generator PT and Transformer PT & Surge cubicles.			

Subsystem: GTB – Generator Transformer

A. Predictive, Maintenance, or Capital Improvements

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase and install GSU Transformer oil continuous dissolved gas analysis monitoring system.			
Purchase and install new digital temperature monitoring system for installation on U1 & U2 GSU Transformer.			
Fully dress and test the spare GSU and Aux Transformers. Install bushings, bushing pockets, and CTs.			This would deplete the spare bushings currently in stock and would necessitate purchase of new high, low, and neutral bushings for stock.

B. Spare Parts

Action Items and Recommendations	Assigned To	Estimated Cost	Comments
Purchase spare neutral grounding resistor bank.			Catastrophic failure of a GSU Transformer would likely cause loss of resistor bank due to proximity.
Review warehouse spare stocking level on GSU surge arresters	Kevin-M		
Review spare parts stocking level on external CTs mounted on GSU high side bushings.	Kevin-M		
Review spare parts stocking level on complete gasket set for GSU	Kevin-M		